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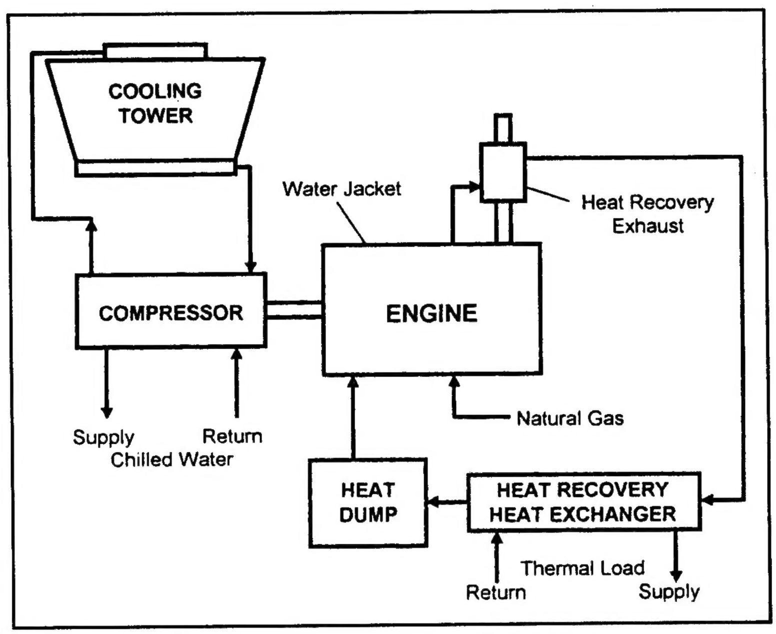
Evaluating Gas-Fueled Cooling Technologies for Application at Army Installations

by
Gerald L. Cler



Electric consumption at DOD fixed facilities accounts for about one-third of the energy consumed, but about two-thirds of the total fixed facility energy expenditures and 30 to 60 percent of the total electric bill, primarily due to summer air conditioning loads. Decreasing electricity use through conservation and/or fuel switching can effectively reduce energy costs at Army Installations. Natural gas cooling technologies may now be viable alternatives for specific applications since both absorption and engine-driven chillers have become available in nearly the same capacities as electric chillers.

This study developed a simple method to evaluate gas cooling technologies as alternatives to conventional electric vapor compression cooling. A worksheet was developed to help users evaluate gas cooling technologies by entering local electric and gas rates, approximate cooling load profiles for building(s) being evaluated, equipment and installation costs, equipment performance and maintenance requirements, and other system parameters. The completed worksheet determines approximate system costs, annual operating costs, and life cycle costs for electric, absorption, and engine-driven chillers. Incremental simple payback and Savings-to-Investment Ratio (SIR) are also calculated for absorption and engine-driven chillers using electric chillers as the base case for comparison.

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Foreword

This study was conducted for U.S. Army Center for Public Works (USACPW) under Reimbursable funding MIPR No. E87930543; Work Unit WS3, "Gas-Fired, Engine-Driven Cooling Systems." The technical monitor was Christopher Irby, CECPW-EM.

The work was performed by the Utilities Division (UL-U) of the Utilities and Industrial Operations Laboratory (UL), U.S. Army Construction Engineering Research Laboratories (USACERL). The USACERL principal investigator was Gerald Cler. Martin J. Savoie is Acting Chief, CECER-UL-U, John T. Bandy is Operations Chief, and Gary W. Schanche is Chief, CECER-UL. The USACERL technical editor was William J. Wolfe, Technical Resources.

COL James T. Scott is Commander and Acting Director of USACERL, and Michael J. O'Connor is Technical Director.

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1 Introduction

Background

Electric chillers are currently used in about 97 percent of all cooling applications. Peak cooling loads typically occur over a relatively short period of time and can cause high fluctuations in the utility load profile. Such large load variations are undesirable since they may cause capacity shortages, often forcing utility companies to employ peaking plants, which are generally inefficient and expensive to operate.

Large commercial and industrial customers typically have two distinct parts to their electric bills: a charge for (1) the energy the customer consumes, and (2) the rate, or demand, at which they consume it. Variations may include time-of-day and seasonal variations in energy rates, seasonal variations in demand charges, and often a ratchet clause. A ratchet clause is a mechanism utility companies use to charge customers for the greater of either the actual peak demand that occurred during the month, or a fixed percentage of the peak demand that occurred during some previous time period, typically the previous 11 months.

Electric consumption at DOD fixed facilities accounts for about one-third of the energy consumed. The remaining two-thirds is a mix of natural gas, liquefied petroleum gas, steam, fuel oil, coal, and a small amount of other sources. While electricity accounts for only one-third of the energy consumed, it accounts for about two-thirds of the total fixed facility energy expenditures. Additionally, electric demand accounts for 30 to 60 percent of the total electric bill, primarily due to summer air conditioning loads. Natural gas, on the other hand, accounts for about 38 percent of the fuel consumed, and only 20 percent of the total energy expenditures.

Reducing the use of electricity, either through energy conservation measures and/or fuel switching, can be an effective way to reduce the energy costs at Army Installations. Natural gas cooling technologies are being evaluated as part of an effort to reduce energy cost. Absorption chillers have been commercially available for many years in a wide range of sizes while engine driven chillers have, until recently, only been available in limited capacities. However, over the last several years engine driven chillers have become available in a much wider range of capacities. Both

absorption and engine driven chillers are now available in nearly the same capacities as electric chillers.

In many areas of the United States, electric demand charges are very high while summer natural gas rates are moderate to low. In many of these regions, natural gas cooling technologies may be a cost effective technology and should be considered in all new construction and whenever an existing chiller is to be replaced. A method to evaluate gas cooling technologies as alternatives to conventional electric vapor compression cooling can help users evaluate these competing technologies to determine which alternative, or combination of alternatives, can provide the most energy-efficient, cost-effective cooling systems for their installation.

Objective

The objectives of this research effort were to develop a simple method for Army installation personnel to evaluate gas cooling technologies as possible alternatives to conventional electric vapor compression cooling technologies. This included an investigation of commercially available gas cooling technologies, performance capabilities, associated costs, and issues relevant to owning, operating, and maintaining the equipment.

Approach

A worksheet was developed to allow users to evaluate gas cooling technologies by entering local electric and gas rates, approximate cooling load profiles for the building(s) being evaluated, equipment and installation costs, equipment performance and maintenance requirements, and other system parameters. Required budget equipment and installation costs along with performance parameters are provided as a starting point. When the user has completed the worksheet, it determines approximate system costs, annual operating costs, and life cycle costs for electric, absorption, and engine-driven chillers. Incremental simple payback and Savings-to-Investment Ratio (SIR) are also calculated for absorption and engine driven chillers using electric chillers as the base case for comparison.

Scope

In its broadest sense, the term "gas cooling" includes a range of technologies: single- and double-effect absorption chillers, internal combustion and Stirling engine-driven

chillers, liquid and solid desiccant dehumidification systems, and absorption and engine driven heat pumps. This study uses the term to refer to absorption and engine driven chillers only.

Mode of Technology Transfer

The findings of this study will help Installation personnel identify economical gas cooling technology applications. Research results should be used to update guidance documents, including *Air Conditioning, Evaporative Cooling, Dehumidification, and Mechanical Ventilation* (AR 420-53); and *Mechanical Design: Heating Ventilation, and Air Conditioning* (TM 5-815-1).

Metric Conversion Factors

U.S. standard units of measure are used throughout this report. A table of metric conversion factors is presented below.

1 in.	=	25.4 mm
1 ft	=	0.305 m
1 yd	=	0.9144 m
1 cu in.	=	16.39 cm^3
1 cu ft	=	0.028 m^3
1 sq ft	=	0.093 m^2
1 sq in.	=	6.452 cm2
1 ton	=	907.1848 kg
1 lb	=	0.453 kg
1 lb/hr	=	0.126 g/s
1 psi	=	89.3 g/cm^2
1 psi	=	6.89 kPa
1 torr	=	133.322 Pa
1 rpm	=	6.0 degrees/sec
1 gal	=	3.78 L
1 gpm	=	0.06308 L/sec
°F	=	(°C x 1.8) + 32
3412 Btu	=	1 kWh
1 hp	=	0.7457 kW

2 Overview of Natural Gas Cooling Technology

As stated previously, this report discusses only absorption and engine driven chillers, and compares their installation, operating and maintenance costs to that of electric chillers. One primary objective of this work was to develop a Level 1 analysis method for determining the economics of gas-fired absorption and engine-driven chillers when compared to a conventional electric vapor compression chiller. The following sections describe the physical characteristics of natural gas cooling equipment and, where appropriate, compares them with electric chillers.

Absorption Chillers

System Operation

Absorption cooling systems, like their compressor-driven counterparts, rely on a cycle of condensation and evaporation to produce cooling (American Gas Cooling Center January 1994). However, the absorption process is driven by a heat source rather than by a mechanical compressor. Direct-fired absorption chillers contain an integral burner to provide the heat source, while the indirect-fired units are powered by steam, hot water, or waste heat from other processes.

The simplest absorption cycle is the single stage, or single-effect, absorption chiller. Figure 1 shows the main components of this cycle. A Lithium-Bromide/water absorbent/refrigerant cooling process in a single-effect absorption chiller follows these steps:

- Liquid refrigerant (water) is sprayed into the evaporator (1) where the very low pressure results in the refrigerant boiling as it absorbs heat from the building chilled water circulating through the tubes in the evaporator, cooling it to about 44 °F.
- The refrigerant vapor produced in the evaporator passes on to the absorber (2) where it is absorbed by the concentrated absorbent (LiBr), which has a strong affinity for water. This process creates a vacuum, which is the driving potential required for the low-pressure evaporator operation.

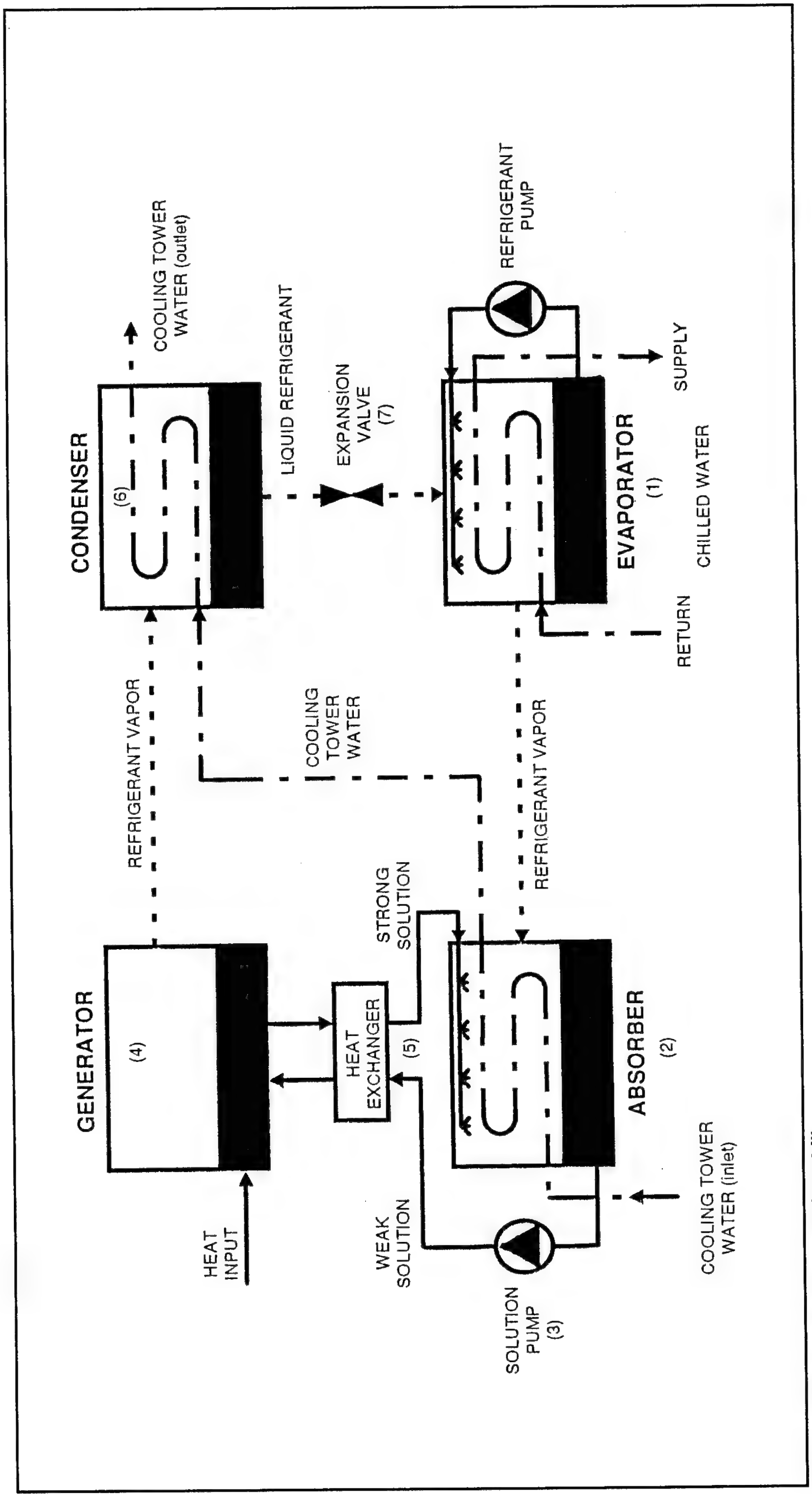

Figure 1. Single-effect absorption chiller.

- As the concentrated solution absorbs more refrigerant, it becomes diluted and its affinity for refrigerant is reduced. The dilute solution is then pumped (3) to the Generator (4). There, heat is added, boiling off the refrigerant and reconcentrating the absorbent solution. The concentrated solution, again with a strong affinity for refrigerant, is pumped back into the Absorber.
- A liquid-to-liquid heat exchanger (5) is typically used to recover heat from the concentrated absorbent leaving the generator and preheating the dilute absorbent solution before it enters the generator.
- The hot refrigerant (water) vapor released from the dilute absorbent solution in the Generator enters the Condenser (6) where it is cooled and condensed to a liquid. The refrigerant then passes through an expansion valve (7) and returns to the evaporator where the process is repeated.

To improve absorption cycle efficiency, manufacturers have added another stage or effect to the simple single-effect cycle. This two-stage, or double-effect absorption chiller is somewhat more complicated and requires more components than the single-effect chiller, but can reduce fuel consumption by 30 to 40 percent. This cycle uses two separate generators to permit recovery and reuse of a large fraction of the input heat used to separate the refrigerant from the absorbent. Figure 2 shows the main components of this cycle. In addition to the process described above for the single-effect chiller, the double-effect absorption chiller has the following additional steps in the cycle:

- Vapor from the high temperature generator (4a) is used as the heat source in the low temperature generator (4b). This process produces additional refrigerant and cools the refrigerant that was produced in the high temperature generator before it enters the Condenser (6).
- Two liquid-to liquid heat exchangers (5a and 5b) are used in this cycle to recover heat from the concentrated absorbent leaving both generators, thereby improving cycle efficiency.

Performance

Single-effect water-cooled absorption chillers have a thermal Coefficient-of-Performance (COP) ranging from about 0.60 to 0.70 and are generally indirectly fired. Therefore, in calculating the energy consumption of the chiller, the boiler efficiency used to provide the steam or hot water must be taken into account. Single-effect chillers require hot water from 160 to 200 °F or 15 to 18 psig steam.

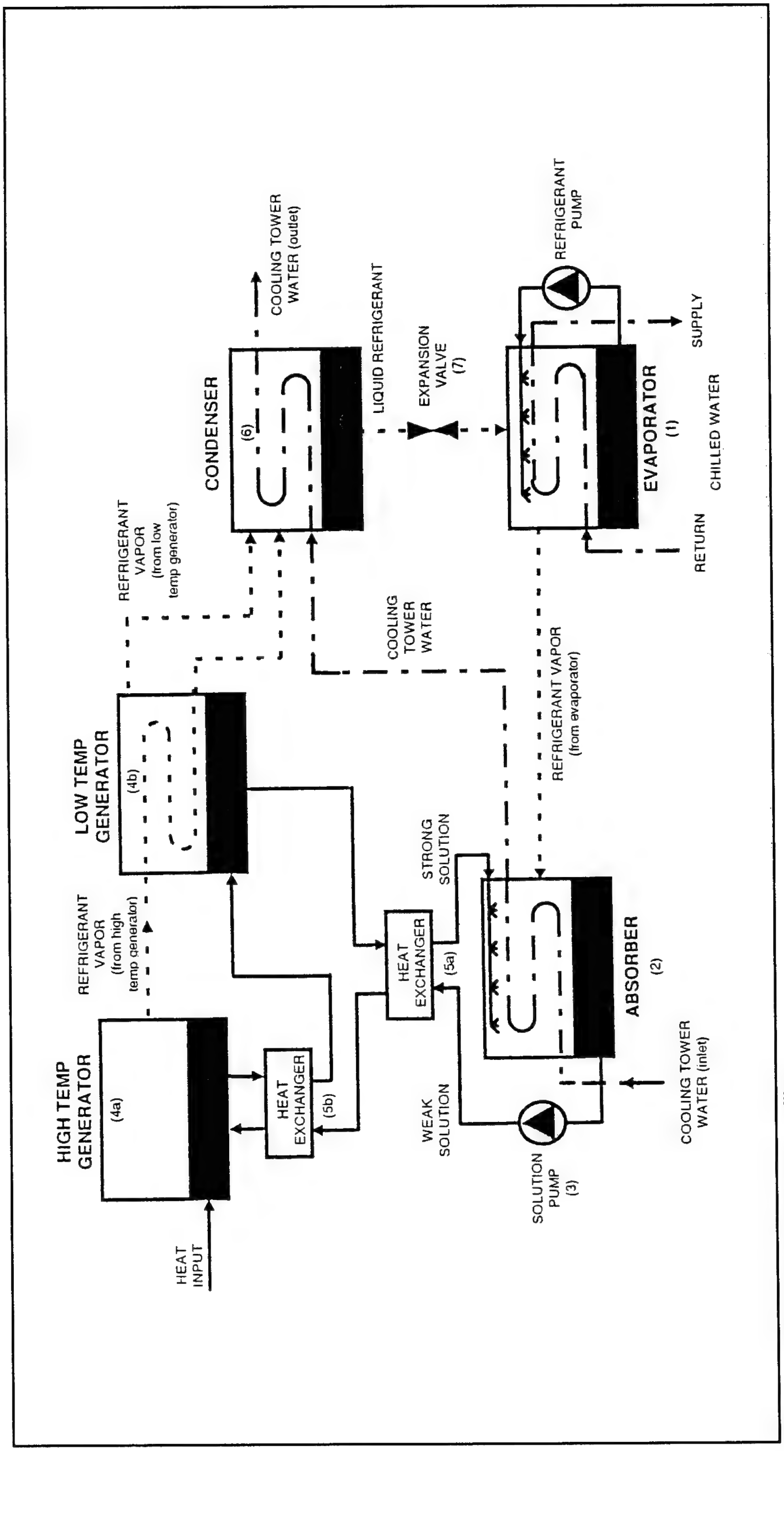

Figure 2. Double-effect absorption chiller.

Double-effect water-cooled chillers are available as direct- or indirect-fired units. Indirect-fired double-effect chillers typically have a COP in the range from 1.0 to 1.20. Again, the boiler efficiency must be included in all energy consumption calculations. Direct-fired double-effect chillers typically have a COP in the range of 0.95 to 1.10. While the COP values for the direct-fired chillers are lower than the indirect-fired units, this value does not need a correction for boiler efficiency since the burner is integral with the chiller and the efficiency is accounted for during the calculation of the COP. Double-effect chillers require generator temperatures of about 300 °F. Consequently, double-effect units must be direct-fired with natural gas or oil, or powered with high pressure steam, nominally 120 psig or higher.

Part load performance of absorption machines is generally very good; they maintain reasonable efficiencies down to about 10 percent of their rated capacity. The cooling output from an absorption chiller is controlled by varying the flow of steam or the firing rate of the burner, thus reducing or increasing the production of concentrated absorbent. Some units use multiple capacity burners to enhance part load performance. COP values are calculated at Air Conditioning and Refrigeration Institute (ARI, Arlington, VA) conditions, based on the higher heating value of natural gas.

Sound attenuation enclosures are not typically required for absorption chillers. Sound levels of 75 to 89 dB at a distance of 3 ft are typical. This, along with their vibration-free operating, can be tangible benefits to owners of absorption chillers in some special applications.

Gas Engine-Driven Chillers

System Operation

A gas engine-driven chiller is similar to an electric chiller except that a gas engine replaces the electric motor of a vapor compression chiller. Gas engines are coupled to open-drive compressors only, whereas electric motors may drive hermetic-, semi-hermetic-, or open-drive compressors. The engine is usually coupled to the compressor through a vibration-isolating coupling and an intermediate gear-box. These components reduce vibrations transmitted from the engine to the compressor and improve performance by matching the optimum speeds of the engine and compressor over a wide range of operating conditions.

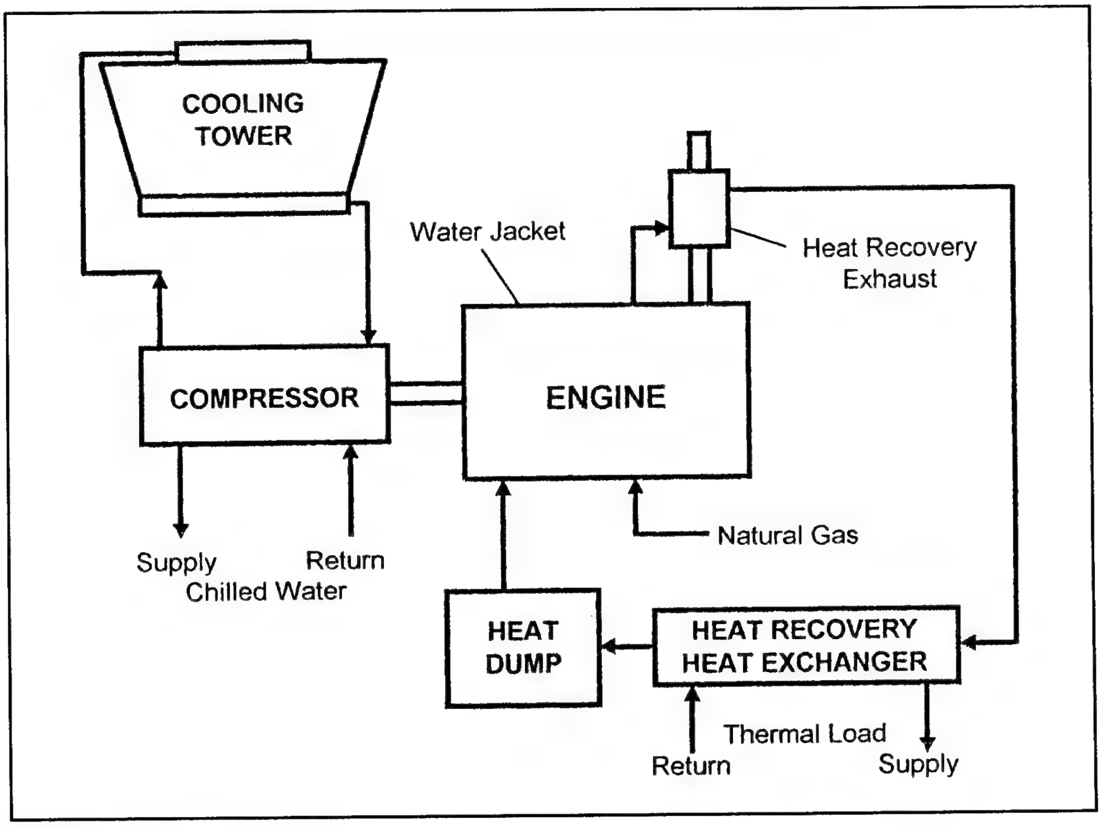

Figure 3. Engine-driven chiller.

Engine-driven chillers employ a conventional vapor compression cycle to produce a cooling effect. Figure 3 shows the main components of this cycle. A "walk through" of an engine-driven vapor-compression cooling cycle consists of:

- Low-pressure liquid refrigerant boils in the evaporator, removing heat from the building as chilled water flows through the evaporator heat exchanger tubes.
- The engine- or electric motor-driven compressor pulls the refrigerant vapor out of the evaporator and compresses the warm, low-pressure refrigerant in the compressor, causing the temperature and the pressure to increase.
- The hot, high pressure refrigerant leaves the compressor and enters the condenser where either cooling water or air cools the refrigerant, causing it to condense to a liquid.
- This liquid refrigerant then passes through an expansion valve, causing its pressure and temperature to drop.
- Low pressure refrigerant enters the evaporator and the cycle is repeated.

System Types

Many different options are possible, depending on the size and type of application. In large commercial applications, an internal combustion engine coupled to a reciprocating, screw, or centrifugal compressors are all available. Reciprocating compressors are generally limited in size up to about 300 tons and typically have the lowest performance. Engine-driven screw compressors are available in capacities ranging from about 125 tons to over 1000 tons and appear to offer a good match over a very wide range of chiller capacities. Centrifugal compressors are typically only used in large tonnage applications.

Heat Recovery

Because a typical engine converts less than a third of its fuel input to shaft power, opportunities exist to recover the remaining fuel energy in the form of engine waste heat. Engine waste heat can be recovered from two main sources: (1) jacket cooling water, which contains about one-third of the fuel input at full load, and (2) exhaust gases, which contain approximately one-fourth of the fuel input. Although most of the jacket water heat can be recovered, only about half of the available exhaust gas heat should be recovered to avoid condensation of water vapor and acids. Heat can be recovered from the engine and used directly for space heating, hot water heating, or for regeneration of a desiccant dehumidification system to obtain additional cooling capacity from the unit.

Performance

Gas engine-driven chiller efficiencies can vary over a wide range depending on the system configuration. Smaller systems (less than 200 tons) typically rely on reciprocating compressors and may have an air- or water-cooled condenser. Air-cooled systems in this capacity range have COPs of about 0.9 to 1.3. When these systems are water cooled, performance can be increased to about 1.5. In large chillers of about 1000 tons, COPs can approach 2.0 without heat recovery.

When a thermal load exists and engine water jacket and/or exhaust heat can be used, a heat recovery package should be included in the system design. In large capacity chillers with applications where a large fraction of the available thermal energy can be used, the overall thermal COP can exceed 2.3.

Part-load performance of engine-driven chillers is generally very good because of this equipment's ability to operate at variable speeds. For instance, above 50 percent part load, reciprocating and screw compressor chillers driven by a gas IC engine may both

have comparable performance since the capacity is modulated by varying engine speed. Below 50 percent, the reciprocating unit part load performance falls off since it must be operated at constant speed while the capacity is varied by cylinder unloading. The screw compressor maintains good part-load performance over a very wide operating range because of its ability to operate at variable displacement down to about 10 percent of rated capacity.

Engine noise in engine driven chiller systems should be a consideration when determining where to install the equipment. Most manufacturers can provide a sound attenuation cover for the engines. (Sound levels of about 79 to 85 dB at a distance of 20 ft are common with the enclosures in place.) This, along with possible vibration, may pose a problem in some applications if proper care is not taken in the design and installation of this equipment.

3 System Costs, Performance, and Maintenance Requirements

This chapter provides much of the information users will need to complete the Level 1 analysis developed in this research effort. The following sections contain information and data that can be used when the actual cost, performance, or maintenance data is not readily available. The information provided here was obtained from several electric, gas engine-driven, and absorption chiller manufacturers. Data was then averaged or curve-fit to provide accurate, but relatively generic, information. Manufacturers provided product information, but no specific maker is associated with cost or operational data cited here. The equipment discussed in the following sections is typically of that used in the commercial sector with capacities starting at about 70 tons of cooling. Where smaller equipment is discussed, it is specifically noted.

Key areas in which information is provided in the following sections are:

- available chiller capacities
- budget equipment and installation costs
- equipment performance
- maintenance costs
- operating costs
- required utility services.

Most of the following data was obtained in early 1995. As of the time of publication of this report, the data is accurate. In the future, caution would be advised to ensure that the cost and availability of equipment is valid. In any case, manufacturers or their representatives should be contacted to obtain the most up-to-date information possible.

Available Chiller Capacities

Electric chillers are available in a wide range and variety of capacities. Small chillers are typically reciprocating-type; medium capacity chillers are typically screw-type; and larger chillers are typically centrifugal. There is much overlap in these ranges, particularly in screw and centrifugal chillers.

Gas engine-driven cooling equipment is available in nearly the same range of capacities as electric chillers, but the number of specific available capacities is generally more limited than for electric chillers. Manufacturers are rapidly filling in voids in capacities and can generally closely match specific job requirements. Again, as with electric chillers, smaller engine driven chillers are typically reciprocating, medium capacity are screw, and only the larger EDC's are centrifugal compressors.

Absorption chillers are available in a very wide range of capacities in double-effect, direct-fired, and both single- and double-effect, indirect-fired chillers. There is no real categorization of absorption chillers possible in capacities greater than 100 tons. Smaller equipment is available, but below this level, while a wide selection of chiller capacities are available, specific equipment types (single- or double-effect, direct- or indirect-fired) are somewhat more limited.

Budget Equipment and Installation Costs

Budget equipment and installation costs for each cooling technology was obtained from equipment manufacturers and then averaged and curve fit to help present the information in a usable manner. No specific manufacturer is associated with any specific data in the following figures.

Information provided for the equipment installation is very general and is based on two main assumptions: (1) that the installation cost includes the installation of the chiller *only*, not the entire chilled water system, and (2) that the installation is a straightforward, new or retrofit, chiller installation that does not require extensive work other than what would be considered a "typical" installation. As stated previously, the data provided here is generic and should be supplemented with site information specific to a given installation whenever possible.

It is very difficult to develop cost correlations for chillers since there are a wide array of parameters that must be considered. The two main issues are capacity and performance. Generally, as capacity increases, the unit cost ($/ton) decreases. As performance increases, the unit cost also increases. The data presented below was used to select and analyze average performance equipment for the chiller type. Figure 4 shows budget equipment costs for a variety of cooling technologies. The data is presented on a dollars-per-ton versus tons-of-cooling- capacity ($/ton vs. tons) basis.

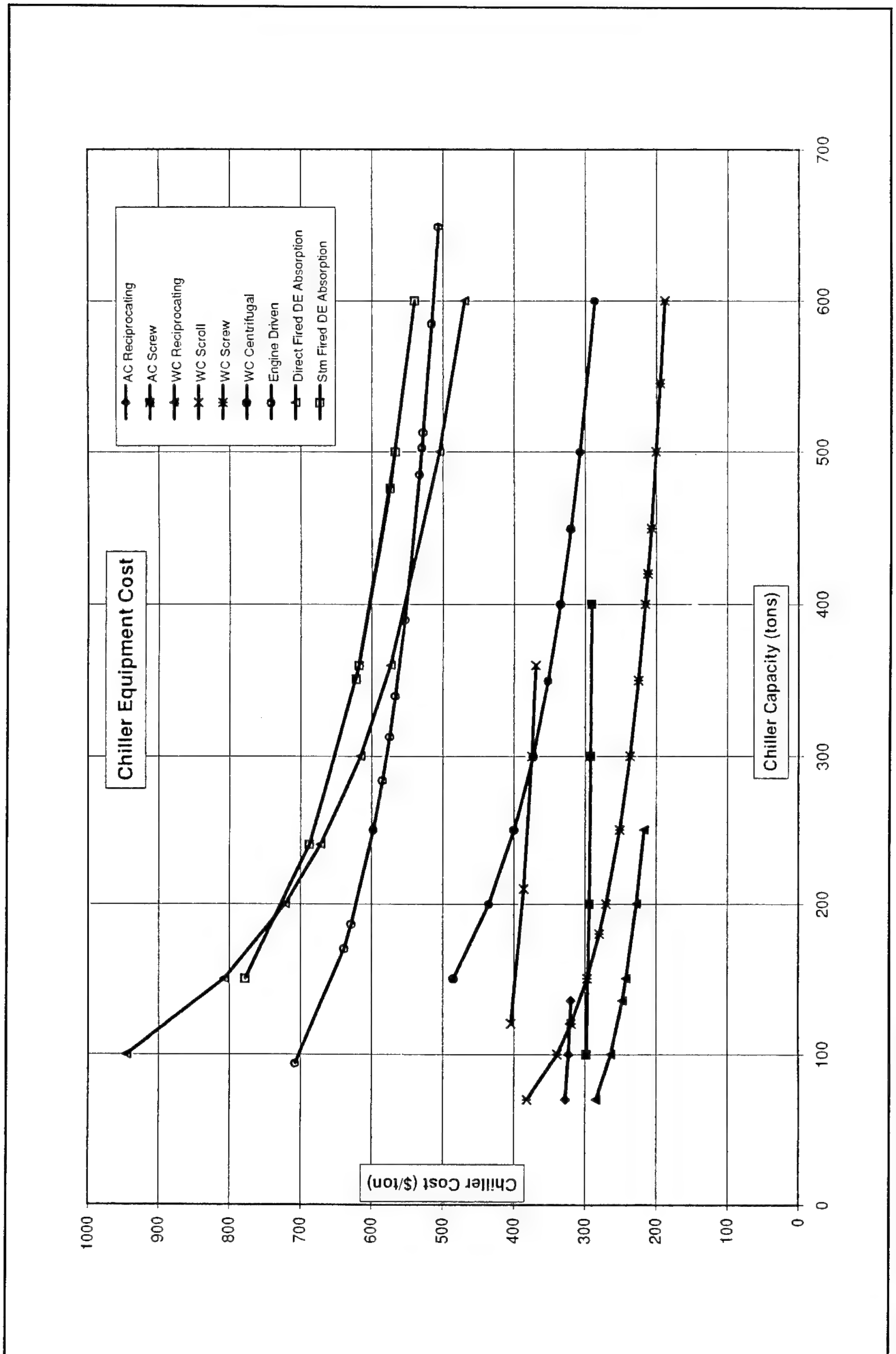

Figure 4. Budget chiller cost curves.

The budget cost curves in Figure 4 were developed from manufacturers' budget costs for a wide range of equipment capacities and manufacturers. Regression analysis techniques were then used to reduce the effort required to perform a basic comparison between electric and gas cooling technologies. The data points shown in Figure 4 are the capacities the manufacturers provided, but the cost are based on the correlations that were developed. In other words, the data points indicate available capacities (not an exhaustive list) while the lines indicate estimated costs.

Figure 5 shows the actual data collected for both electric centrifugal (four manufacturers) and gas engine-driven chillers (three manufacturers) along with the curve that was developed and presented in Figure 4. The figures show a reasonable agreement in equipment cost among manufacturers. When one considers the variations in performance, the cost differences vary even less.

Figure 6 shows cost estimates for installation of chiller equipment. Since there is large variation in each application, it is again difficult to obtain installation cost curves truly representative of a specific project. The data provided in Figure 6 represent approximately 100 applications and can be used as an estimate for basic analysis only. If, after this analysis is performed, either EDCs or absorption chiller prove to be cost effective, a detailed budget cost will be developed and a more detailed cost analysis should be performed.

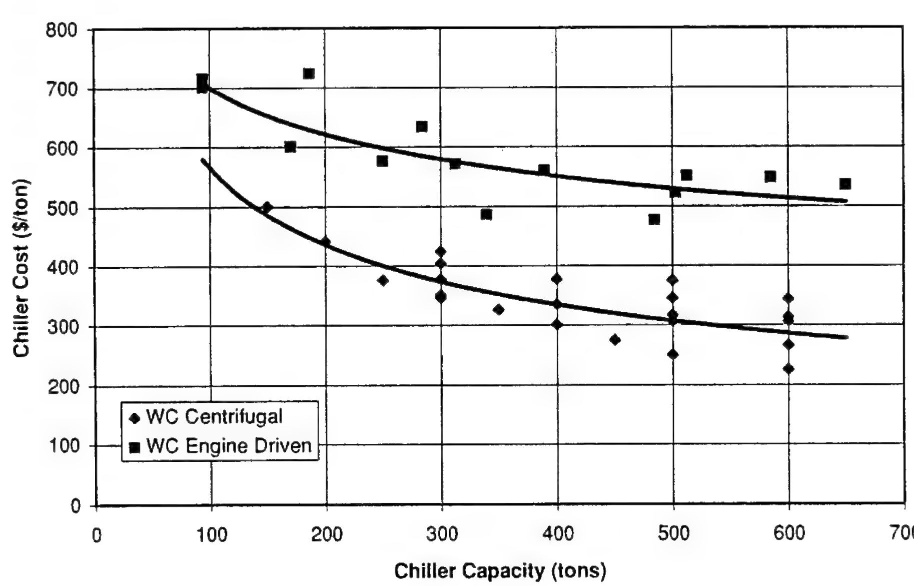

Figure 5. Typical manufacturers chiller budget cost data.

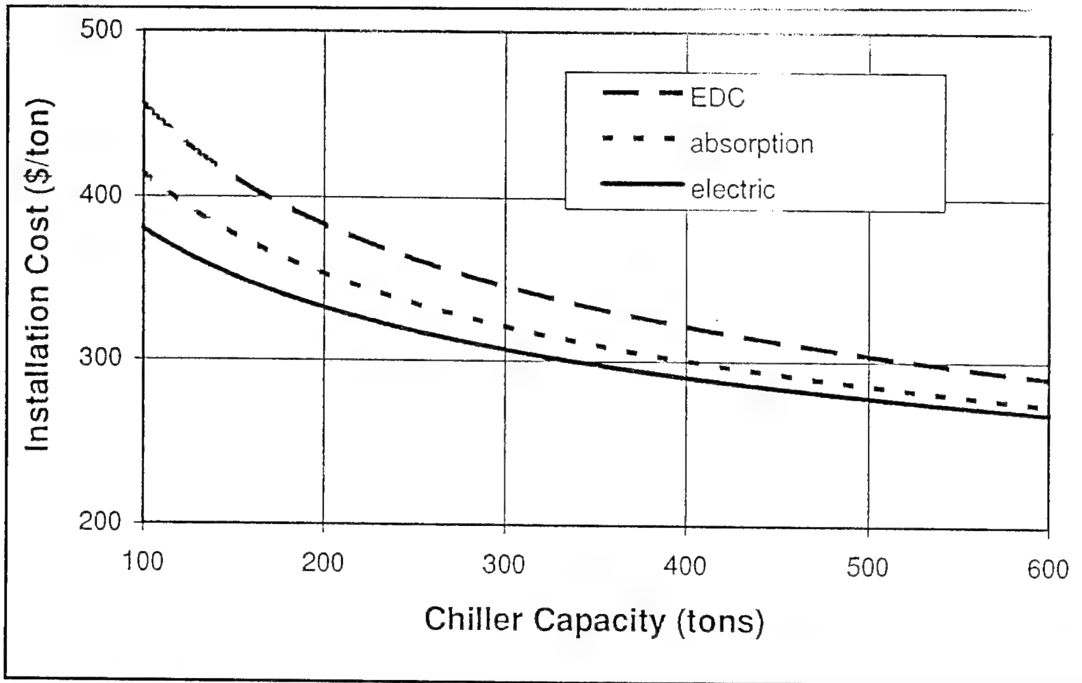

Figure 6. Chiller installation cost estimates.

In nearly all cases, the larger the cooling capacity, the lower the cost per ton. One may then be tempted to install one large chiller that can meet the entire cooling load instead of two or more smaller chillers. In smaller applications, this is a reasonable approach as the cost per ton rises rapidly as capacity decreases below about 200 tons. There are several factors that must be considered when selecting chillers, including: (1) the fraction of installed capacity at which the chiller plant will typically operate, (2) whether a hybrid chiller plant (gas and electric chillers in the same plant) would make economic sense, and (3) how critical the cooling loads are.

It is important to consider the fraction of installed capacity at which the chiller plant will typically operate. A chiller is rarely operated at rated capacity more than a few hundred hours per year. Two or more smaller chillers may be more efficient to operate and therefore have a lower life-cycle owning and operating cost than one larger chiller. For example, one chiller may be sized to meet the typical nighttime cooling load with the second sized to meet the remaining load.

In some circumstances, a hybrid chiller plant may make economic sense. In many applications, a combination of gas and electric chillers will have the lowest life cycle cost. The typical strategy would be to operate the gas chiller during the electric utilities on-peak period as the base loaded chiller followed by the electric chiller. During the off-peak period, the electric unit would be the lead and the gas chiller would be the lag chiller. This operating strategy can significantly reduce the annual

operating hours for the gas chiller while obtaining a significant electrical demand reduction. Additionally, this strategy takes advantage of the fact that the peak electric load typically occurs during the day. Therefore, running an electric chiller at night generally has no impact on the demand portion of the electric utility bill.

It is assumed that all cooling loads are critical to some extent or another, otherwise the facility would not be cooled. Therefore, a chiller plant with only one chiller has no redundancy. During times of chiller maintenance, scheduled or otherwise, the will be no cooling available. Applications in computer centers, hospitals, and many industrial locations require some redundancy, i.e., installation of multiple chillers.

Equipment Performance

Typically, the performance of an electric chiller is rated in terms of kilowatts of electricity required to produce 1 ton of cooling (kW/ton), whereas gas cooling equipment is rated in terms of BTUs of cooling output per Btu of energy input or COP. These rating methods have different engineering units and are therefore not directly comparable. Although conversion to similar units is possible, a direct comparison of the energy performance of electric and gas cooling technologies is not very meaningful and is difficult to determine. An electric chiller will use less site energy than its gas counterpart, but may use the same or more source energy than a gas chiller when all energy production, generation, transmission, and conversion efficiencies and losses are accounted for. It is not the goal of this study to compare absolute energy consumptions of different technologies, only to analyze the cost comparison of these technologies. A brief overview of energy consumption is provided in Chapter 5.

Figures 7 to 9 show the performance estimates for a variety of absorption and engine-driven chillers. Figure 7 shows that the performance of absorption chillers is independent of capacity, but dependent on chiller type. Steam-fired, single- and double-effect absorption chillers have full load COPs of about 0.7 and 1.2, respectively. One must remember to account for the boiler efficiency when calculating the operating costs of indirect-fired absorption chillers. The double-effect, direct-fired absorption chiller has COP of slightly greater than 1. The equipment performance shown in Figure 7 is all for water-cooled equipment.

Figure 8 shows the performance of engine-driven chillers with air-cooled condensers. These are available in capacities up to about 250 tons. As for absorption chillers, the performance of air- cooled equipment is fairly independent of capacity when no heat

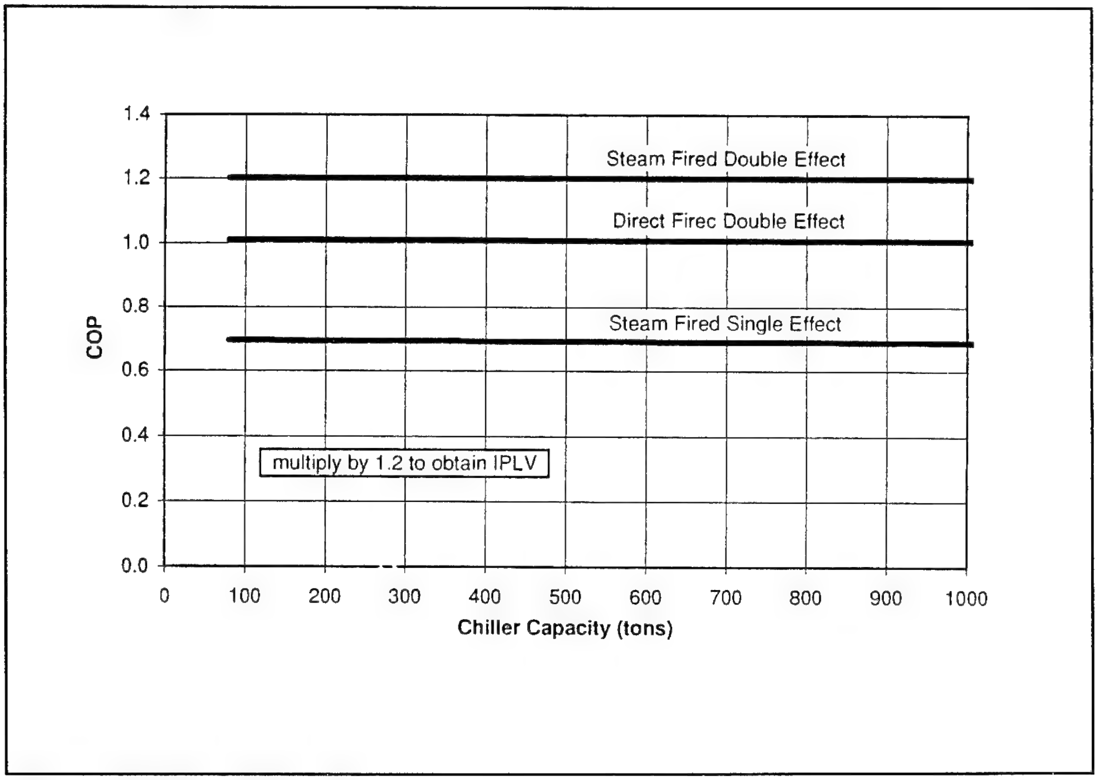

Figure 7. Absorption chiller performance.

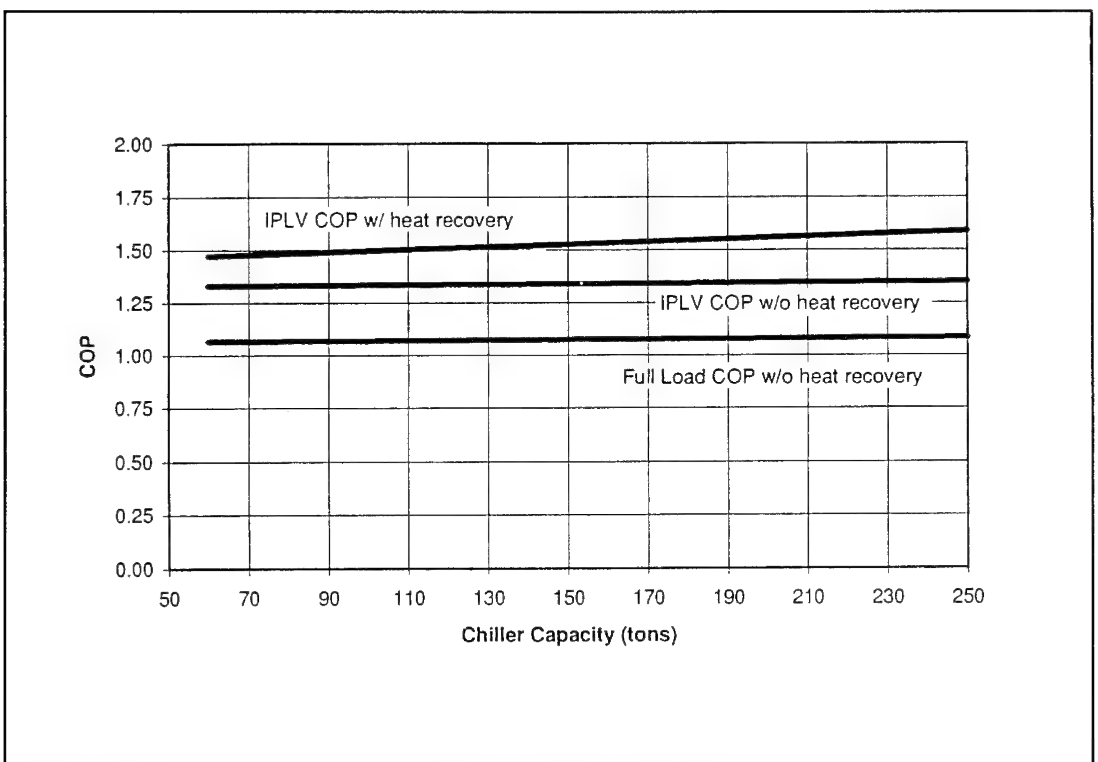

Figure 8. Engine-driven chiller performance–air cooled condenser.

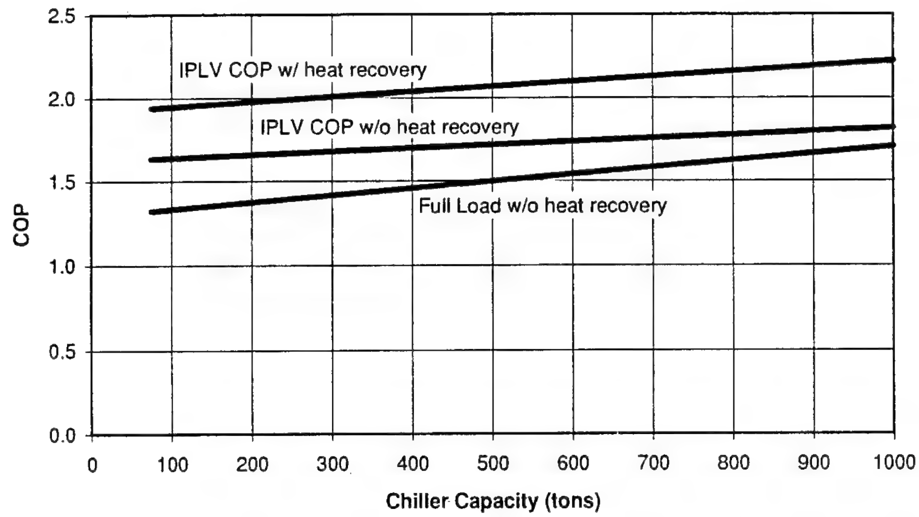

Figure 9. Engine-driven chiller performance–water cooled condenser.

from the water jacket is being recovered. Typical COP for air-cooled EDC without heat recovery is about 1.1 and does vary with specific equipment.

When thermal energy from the engine water jacket can be used, the overall system performance is increased. Figure 8 shows that performance can be increased by 30 to 40 percent in applications where all thermal energy can be used. The resulting system COP can exceed 1.5.

Figure 9 shows the performance of engine driven chillers with water cooled condensers. As seen here, much higher performance is obtained when water-cooled condensers are used. The drawback to this is that the cooling tower will require additional maintenance. However, the operational cost savings generally far outweighs the added maintenance costs. Generally, water-cooled equipment should be considered for any equipment with a capacity of 100 tons or more and are often used with chillers of 50 tons of capacity. As manufacturers continue to improve cooling tower performance and reduce the size and weight of towers, water-cooled equipment will provide the best option for chillers with capacities considerably below even these capacities.

In addition to the gas energy required to drive an absorption or engine-driven chiller, electricity is also required to run the solution pumps for absorption chillers and cooling water pumps for EDCs. These chiller parasitic power requirements are typically small relative to the chiller capacity, but do need to be accounted for in any economic cost comparison of gas and electric chillers. Depending on the chiller capacity and type, electric parasitic power requirements for gas cooling technologies can range from 1 to 5 percent of the electricity required for an electric chiller. Figure 10 shows typical parasitic power requirements for gas cooling technologies vs chiller capacity. Parasitic power requirements for electric chillers, such as purge compressor, are generally included in the chiller performance rating and therefore no additional requirements are needed.

Electricity consumption of the auxiliary equipment in the cooling system must be accounted for since these vary not only with cooling equipment capacity, but also by chiller technology. Auxiliary equipment included here are the evaporator and condenser pumps and the cooling tower fan(s). This is the equipment needed for the production and distribution of chilled water, but does not include motor horsepower in the fan coil units.

The evaporator pump horsepower is independent of the type of chiller installed since all chiller technologies typically specify about 2.5 gpm/ton of cooling. While not

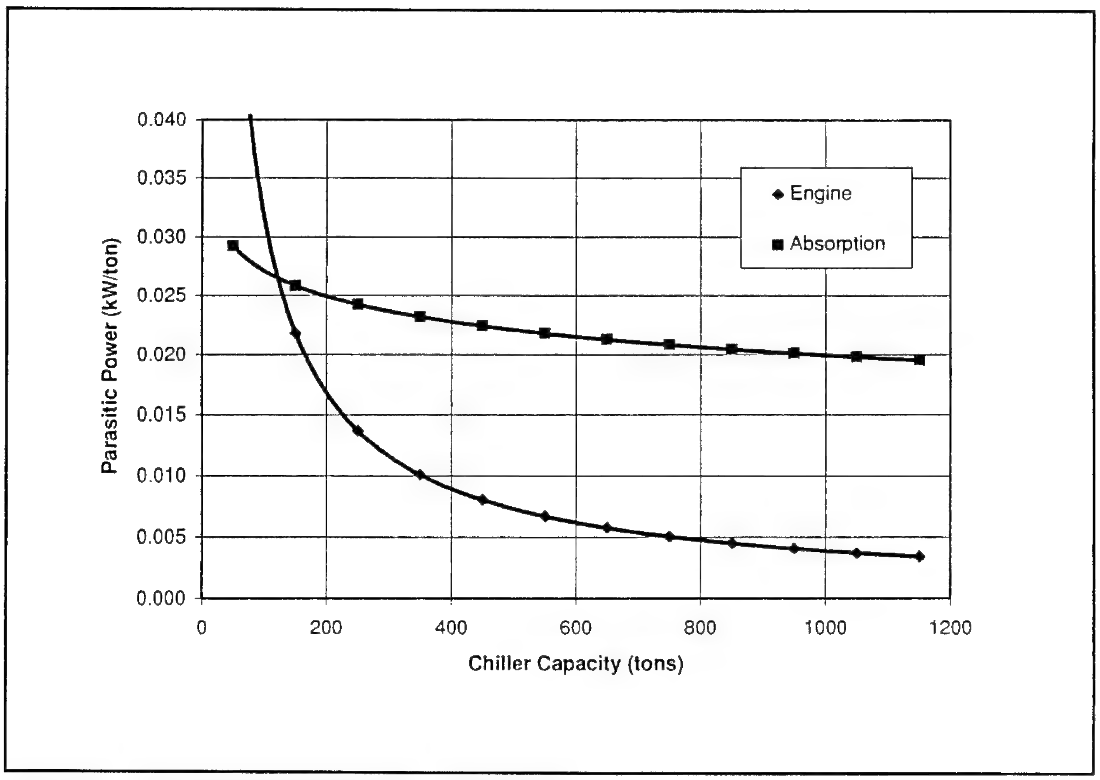

Figure 10. Gas chiller parasitic power requirements.

varying with chiller type, evaporator pump kW/ton ratio does tend to increase with chiller capacity. In general, this is due to the proportionally longer pipe runs and resultant greater system pressure drop in larger buildings or distribution systems used in central chiller plants (Figure 11). Correlation in this figure were developed from data from 29 single building and central chiller plants, all electric chillers.

The cooling tower is typically located as close as possible to the mechanical room or central chiller plant. Piping pressure drops are generally small and therefore a reasonable correlation between chiller capacity and condenser water pump horsepower should exist. One would therefore expect then that the unit power required for the condenser pump to be fairly independent of chiller capacity. Again, Figure 11 shows that only a slight increase in unit power requirements accompanies a chiller capacity increase. As chiller capacity increases, so does the typical distance to the cooling tower, but not to a great extent. Therefore, the increase in power requirements per ton of cooling shows only a slight upward trend.

A similar relationship between chiller capacity and cooling tower fan horsepower exists. This relationship differs from both the evaporator and condenser pump

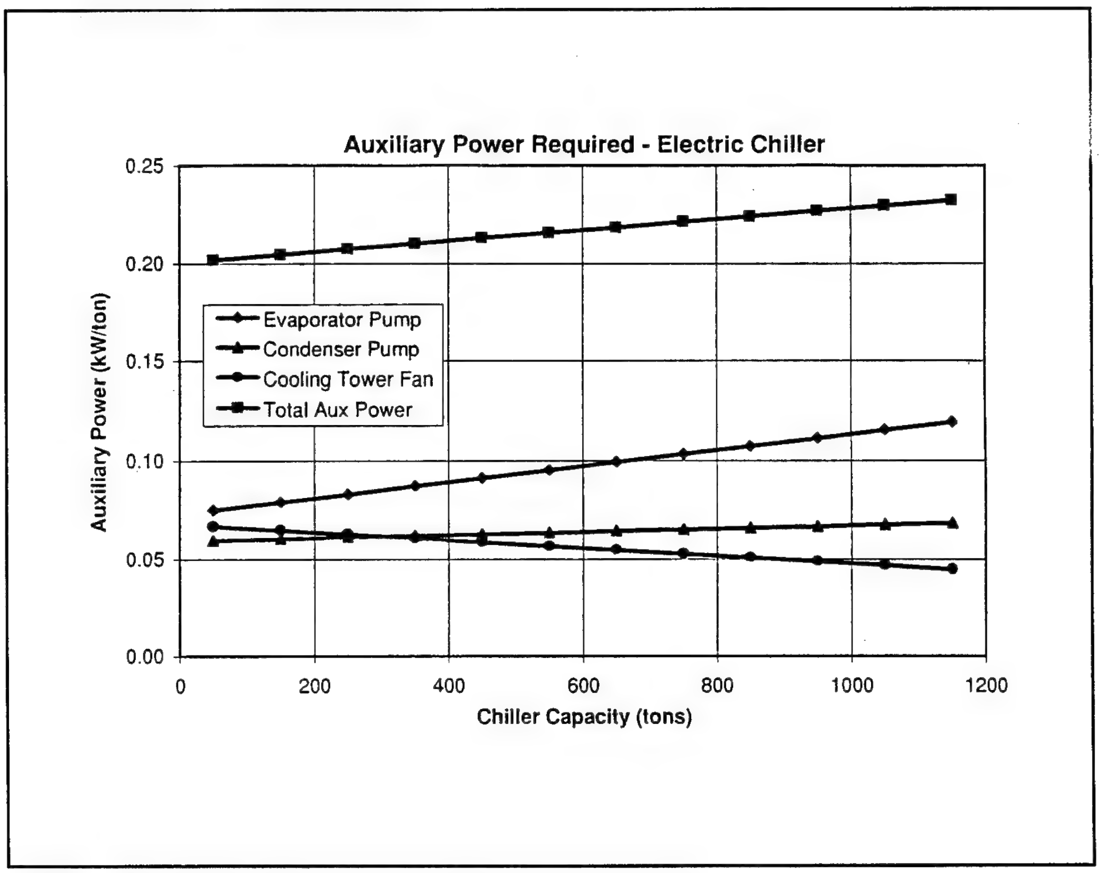

Figure 11. Electric chiller–system auxiliary power requirements.

requirements in that it is an inverse relationship. As the chiller capacity increases, so do the cooling tower physical dimensions. Cooling towers are typically rectangular; therefore, as their capacity (size) increases, the resistance to air flow tends to decrease (Figure 11).

Figure 12 shows data from a number of chiller plants located at Fort Hood, TX. This data is for a wide range of chiller plants consisting of one or two chillers and shows the typical scatter expected in the auxiliary requirements for various chiller plant arrangements and capacities. The scatter in this real world data shows that, until a system is completely designed and all pipe sizes and lengths are known, it is difficult to get an accurate estimate of the power required.

Condenser pump and cooling tower fan horsepower depend on the cooling technology due to the "local" combustion process in either the engine of the EDC or the generator of the absorption chiller, as opposed to the "remote" combustion process of the electric utility. The higher the system COP, the greater the efficiency and therefore the less "extra" heat to be removed. In an EDC with a large, continuous thermal heat recovery capability, the added cooling requirements may be minimal whereas in an absorption

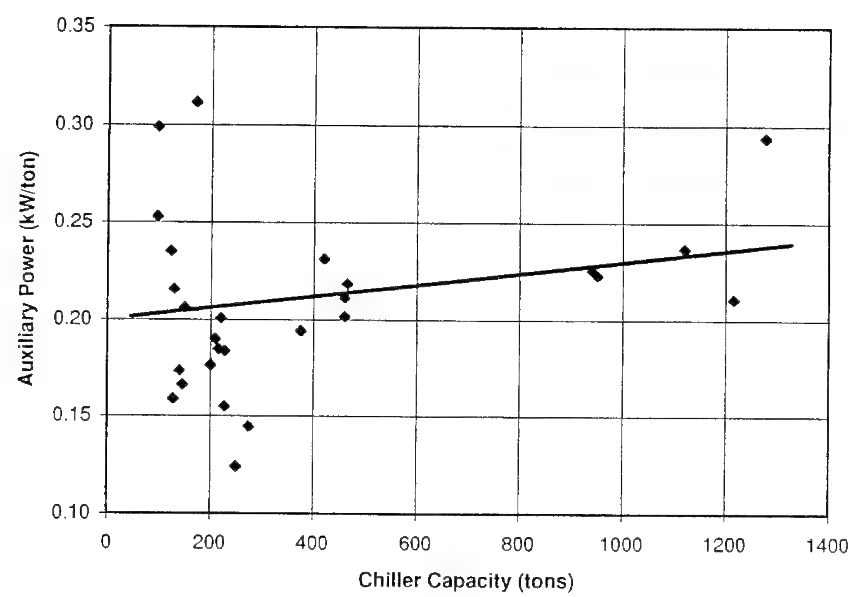

Figure 12. Fort Hood electric chiller auxiliary electric power.

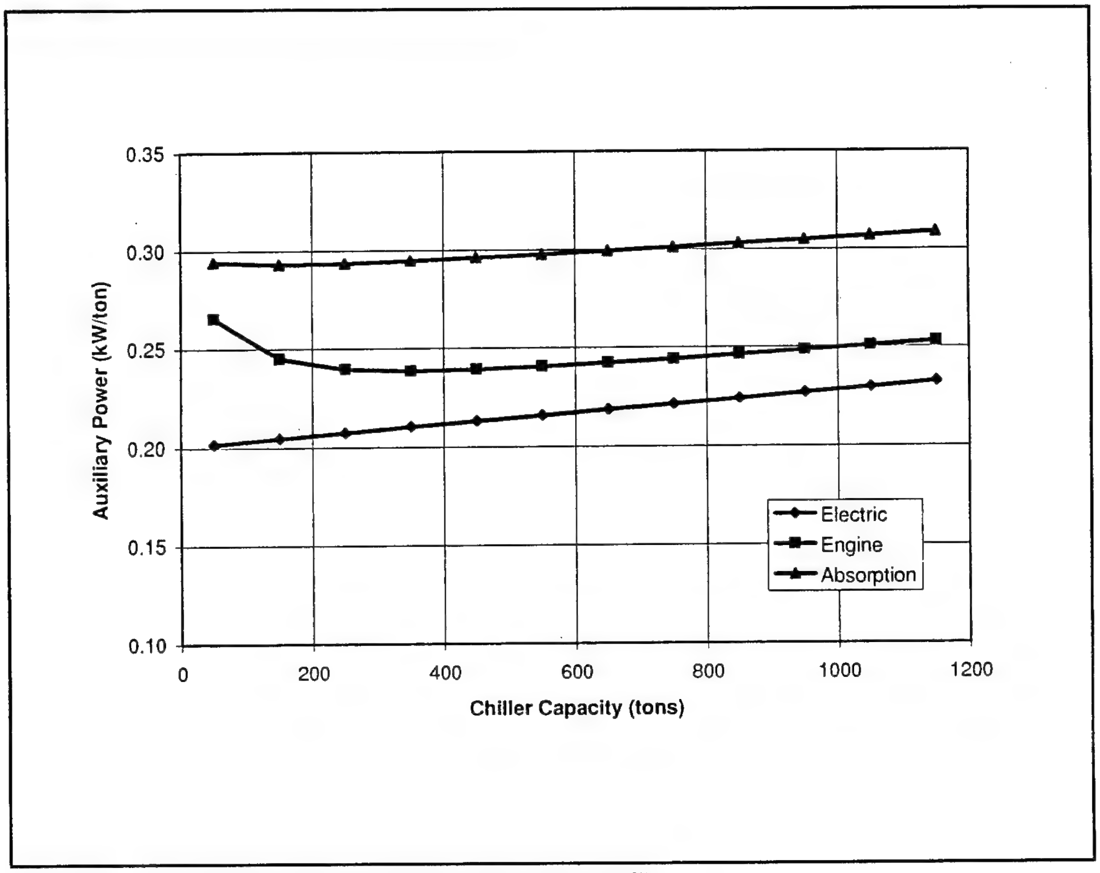

Figure 13. Auxiliary electric power for electric and gas chillers.

chiller, the heat rejected is 50 to 60 percent greater than for an electric chiller. Figure 13 presents estimates of the auxiliary electric power requirements for each of the chiller technologies for a range of equipment cooling capacities. These curves include estimates for evaporator and condenser pumps, cooling tower fan, and also any parasitic power required for either the absorption or engine driven chiller.

Maintenance and Make-Up Water Requirements

Maintenance

All chillers require maintenance. Service requirements and intervals, and the expertise level of the service technician all vary depending on the chiller technology. Nearly all chillers used in the United States are electric; it follows that maintenance personnel are most familiar with the maintenance requirements of these chillers. While absorption and EDCs require maintenance activities that are different than that required by electric chillers, many of the requirements are similar. Regular mainte-

nance is the only way to ensure that equipment will operate properly and at peak performance for its expected life.

Electric, absorption, and engine driven chillers all have some common maintenance requirements. Five general areas of common maintenance include:

1. *All chillers require an annual checkout and calibration, if necessary, of all controls.* Microelectronics have substantially reduced control maintenance requirements, but a control or sensor problem can cause the chiller to operate inefficiently or shut down completely.
2. *All chillers require period (annual) tube cleaning.* Requirements for electric and engine driven chillers are the same since they have similar evaporators and condensers while absorption chiller tube cleaning is slightly more extensive as the absorber tube bundle also requires cleaning.
3. *Chillers contain fluids that require periodic checking.* Electric and engine-driven chillers require checking of the refrigerant and oil level, quantity, and quality, while absorption chillers require regular checks on the inhibitors and quality of the water and LiBr solution.
4. *All units have ancillary equipment that must be periodically checked.* These components include purges on all equipment, solution pumps on absorption machines, cooling water pumps on EDCs along with other components.
5. *Auxiliary equipment, such as the evaporator and condenser pumps and cooling tower fans all require periodic service.* While these components are not directly part of the chiller, if not properly maintained they can also cause the chiller to shut down.

Specific maintenance is also required for the natural gas-fired engine of an engine-driven chiller. These maintenance items include changing oil, oil filters, and air filters; checking belts; checking fluid levels; changing spark plugs and wires; adjusting valves; adjusting ignition timing and carburetor settings; and doing various other routine maintenance. Additionally, the engine will need to have top end maintenance performed, valves and seats ground or replaced, replace springs, etc. on a multiyear cycle, and then also a complete engine rebuild will be required, depending on use, on a 5- to 10-year cycle.

Maintenance for chillers can be provided by the manufacturer or one of its service representatives. This type of maintenance contract can typically be custom tailored to meet the specific requirements of the owner. The owner may provide the regularly scheduled maintenance for an EDC such as changing oil, oil and air filters, spark plugs and wires, etc. and contract with the manufacturer for oil sampling, carburetion adjustments, engine compression checks, etc. The owner may wish to contract out all

or none of the service. Manufacturers tend to be flexible in developing service agreements and also tend to offer a lower rate for services contracted over longer periods. At least one manufacturer will enter into service contract of up to 20 years. The cost per ton-hour (t-h) of cooling for a 20-year contract for similar services is approximately two-thirds of that for a 5-year contract. Long-term contracts are typically adjusted for inflation or other economic indicators on a predetermined schedule.

Maintenance contracts for chillers are typically arranged for on a "dollars per ton per year" or, as is more commonly done for an engine-driven chiller, "dollars per ton-hour." These costs are typically less for larger chillers and range from $0.02/t-h for smaller chillers with shorter (annual) contracts to about $0.01/t-h for large capacity industrial engines with 20-year contracts for a complete, comprehensive maintenance program. Multiyear contracts are typically incremented annually based on inflation or some other cost index.

Similar maintenance cost estimates can be obtained for electric and absorption chillers. These typically range from $0.005 to $0.007/t-h for electric and $0.007 to $0.009/t-h for absorption chillers. As one would expect, the cost of maintaining an engine driven chiller is somewhat more expensive than for maintaining either an electric or absorption chiller. This is to be expected for several reasons. Electric chillers are used in more applications and the maintenance costs are better defined due to the large fleet and many years of operation. Absorption chillers have very few moving parts, thereby minimizing component wear. On the other hand, an engine has more expendable parts and many moving parts, creating higher wear and greater maintenance costs (Table 1).

Table 1. Chiller maintenance cost estimates.

Chiller Type	Maint Cost ($/t-h)
Electric	$0.005 – $0.007/t-h
Absorption	$0.007 – $0.009/t-h
Engine Driven	$0.01 – $0.02/t-h

Annual maintenance costs can be estimated by knowing the annual equivalent full load hours (EFLH) of operation, maintenance costs, and chiller capacity:

$$\text{Annual Maintenance Cost (\$)} = \text{EFLH (hours)} \times \text{chiller capacity (tons)} \times \text{maint. cost (\$/t-h)} \quad \text{[Eq 1]}$$

For example, a 500-ton engine-driven chiller operated 1500 EFLH/yr with a maintenance contract cost of $0.015/t-h would create an annual maintenance cost of:

$$\begin{aligned}\text{Annual maintenance cost} &= 500 \text{ tons} \times 1500 \text{ hours} \times \$0.015/\text{t-h} \\ &= \$11{,}250\end{aligned}$$

Make-Up Water Requirements

Chillers are either air- or water-cooled. Typically, smaller chillers are air-cooled while larger chillers are water-cooled. There is considerable overlap in the break between air- and water- cooled equipment. Any chiller can be air- or water-cooled. Typically, chillers up to a couple hundred tons might be considered for air-cooled applications while chillers over 75 tons might be considered for water-cooled applications. There are two main considerations that influence the selection of a cooling medium for a chiller condenser: (1) an air-cooled condenser typically requires less maintenance (although it will *not* be maintenance-free), and (2) a water-cooled chiller will use considerably less energy (on the order of one-third less) than an air-cooled chiller.

Costs associated with purchasing, treating, and disposing of water depend on the cooling technology being considered. Heat rejection from electric chillers is lower than either EDCs or absorption chillers. Make-up water requirements for an electric chiller are on the order of 4 galper ton-hour of cooling. An EDC requires about 4.3 gal/t-h, or 10 percent more make-up water than an electric chiller while an absorption chiller requires about 6.2 gal/t-h, or 50 to 60 percent more make-up water. The cost to purchase, chemically treat, and dispose of the bleed-off water from a cooling tower is estimated to be approximately $4.00/kgal. This value can vary significantly depending on several factors, including the water quality. Therefore, the treatment required and quantity of chemicals, service performed in-house or contract to water treatment specialists, and the type and frequency of services provided will also vary. Based on the above estimates, the cost for make-up water per ton-hour of cooling can be calculated for each cooling technology (Table 2). Depending on the local climate, chiller load, and other factors, the make-up water requirements and consequent cost will vary.

Table 2. Chiller make-up water requirements.

Chiller Type	Required Make-Up Water (gal/t-h)	$/t-h
Electric	4.0	0.016
Double-effect absorption	6.2	0.025
Engine-driven	4.3	0.017

The annual cost for make-up water can be estimated from the annual EFLH of operation, water costs, and chiller capacity:

$$\text{Annual make-up water cost (\$)} = \text{EFLH (hours)} \times \text{chiller capacity (tons)} \times \text{water cost (\$/t-h)} \qquad \text{[Eq 2]}$$

For example, a 500-ton engine-driven chiller operated 1500 EFLH/yr, with a maintenance contract cost of $0.017/t-h, would create an annual make-up water cost of:

$$\begin{aligned}\text{Annual make-up water cost} &= 500 \text{ tons} \times 1500 \text{ hours} \times \$0.017/\text{t-h} \\ &= \$12{,}750\end{aligned}$$

4 Economic Evaluation of Gas Cooling Technologies

Required Information

This chapter describes the use of the gas cooling analysis worksheets. Some site-specific information is required for the user to complete the worksheets. Some of this information, such as utility rates, should be available from the utility company and/or from the utility bills. Other information, such as the facility cooling load and boiler efficiency (if heat recovery from an engine driven chiller is being considered), can usually be estimated. If any information (such as chiller performance or monitored cooling loads) is available from previous studies or monitoring programs, this information should be used instead of estimates.

Chapter 3 gave non-site-specific information, such as chiller performance, equipment and maintenance costs, and parasitic energy requirements. This chapter gives required information for specific projects being considered.

Description of Evaluation Worksheets

A description of each user-provided input and/or calculation is contained in this section. Many of the inputs are straightforward and only a very brief explanation is given. Others, specifically the calculation of the demand charge resulting from the operating of the chiller plant, are somewhat more complex and a more detailed explanation is given. The numbered descriptions correspond to the data in the worksheets.

When the user is required to reference previously entered data, the following nomenclature is used. When calculations are required, the needed data is specified by line and column number or letter within parentheses (). The data elements are identified by specifying the line, column, and sub-line. For example, the Integrated Part Load Value (IPLV) for an engine driven chiller would be specified as 14C2 (see Figure 14, p 49 for this data element). A colon is used to indicate that the indicated operation is to be performed on all elements between the two separated by the colon;

e.g., (sum{22I1:22I12}) means to add together elements 22I1, 22I2, 22I3...22I12. Begin the worksheet as follows:

1. *Enter the facility name.*

2. *Enter the date.*

3. *Enter the users name.*

4. *Enter the building(s) peak cooling load.* In a retrofit application, the capacity of the existing chiller can usually be used for this analysis. The final design may specify a chiller with a different capacity as a result of increased loads or reduced loads as a result of energy conservation measures. This will have minimal impact on this study.

5. *Enter the total number of annual operating hours from the beginning of the cooling season to its end.* If the chiller is on constantly multiply 24 hr per day by the number of days in the cooling season. If the chiller is turned off at night or on weekends, be sure to account for only the hours that the chiller is on.

6. *Enter the fraction, as a decimal [0.00], that represents the average annual loading on the chiller.* Typical values range from 0.50 to 0.65. Depending on climate, application, and perhaps other parameters, this value can be higher or lower than this range.

7. *Enter the peak cooling load for each month of the cooling season.* This value is used to develop an estimate of the annual cooling load profile.

8. *Enter any electric utility rebates (Line 8A) and gas utility rebates (Line 8B) that are available.* When entering this data in Lines 25D, 31D, 37D, and 43D, be sure to only enter the appropriate rebate. Gas utility rebates typically apply only for the installation of gas cooling equipment, whereas electric utility rebates may apply for either high efficiency electric chillers, or for the customer to switch from electric to gas cooling equipment. Enter the data as a $/ ton value.

9. *Enter the Natural Gas Rates.* In (Line 9A) enter the price the utility will charge for natural gas for the cooling system. Be sure to check with the local gas utility to see if they have reduced rates for cooling projects.

10. *Enter the Summer electric monthly demand charge in (Line 10A).* This value should be available from the electric bills, electric rate contract, or from the

utility company. In spaces (Line 10B) and (Line 10C), enter the months in which the summer demand charge is in effect.

11. *Enter the demand ratchet imposed by the electric utility.* This value is available from the rate contract or from the utility company. Ratchet charges affect the minimum amount of electrical demand that the utility will bill the customer each month. Most ratchet clauses require that the customer pay the greater of either: (1) the current month's actual demand, or (2) the ratchet fraction multiplied by the greatest demand that occurred during some previous time period, typically the previous 11 months.

12. *Enter the Winter electric monthly demand charge in Line 12.* This value should be available from the electric bills, the electric rate contract, or the utility company. The monthly demand charge may be the same year round so that (Line 10B) and (Line 10C) should be "January" and "December" respectively.

13. *Enter the energy charge assessed by the utility.* Be sure to account for any fuel adjustments. Often a utility will have multiple rates based on time of day, season, or on the quantity of energy purchased during the month (a tiered rate schedule where the first kWh's are more expensive than later kWh's). If there are variations in the rate schedule, an estimate of the weighted average of the cost per kWh will provide an adequate value for this analysis.

14. *Cooling equipment energy requirements.* The data required for each cooling technology must be provided. Peak values (column 1) will be used to estimate the electrical demand for each month of the cooling season, based on the values entered in Number 7 above. The Integrated Part Load Value (IPLV) (column 2) will be used to calculate the energy consumption by the chiller during the cooling season. Average values are provided Figures 7, 8, and 9 in Chapter 3 if data is not available for the specific chiller being considered. Parasitic Electrical Requirements (column 3) are estimates of the electrical requirements for the chilled water pumps, condenser water pumps, cooling tower fans, and any auxiliary power that the chiller may require, such as water jacket pump on an engine driven chiller. These values are listed on a kW/ton basis. If actual pump and fan motor data is used, convert the horsepower to kW, divide by the motor efficiency (η), and divide by the chiller capacity $\{hp \times 0.746/(\eta \times tons)\}$. Be sure to include an estimate of the auxiliary power required by the absorption and engine driven chillers. This data can also be obtained from Figure 13.

15. *Enter the recoverable thermal energy that can be used by the facility in (Line 15A).* Possible applications include heating DHW, pre-heating boiler make-up water

and/or condensate return. Using the thermal energy to regenerate a desiccant dehumidification system is another option that could reduce the required chiller capacity and improve the overall system efficiency. Enter the boiler efficiency in (Line 15B).

16. *Enter values for Equipment, Installation, and Maintenance costs in $/ton of chiller capacity*. Estimates of the chiller equipment and installation costs are available from Figures 4 and 6 in Chapter 3. Maintenance and make-up water costs are also available in Tables 1 and 2, respectively, in Chapter 3. Appropriate values for each technology must be used. Typically, electric chillers are the least expensive to purchase, install, and maintain, followed by absorption chillers, then by engine-driven chillers. Make-up water requirements are lowest for electric chillers and highest for absorption chillers. Engine-driven chillers' make-up water requirements are only slightly higher than those of their electric counterparts.

    At this point, all user provided information has been entered. The following calculations are required to determine the owning and operating costs associated with each chiller technology.

17. *Cooling Hours*. To calculate the annual Equivalent Full Load Hours, multiply the annual operating hours of the cooling season (Line 5) by the equivalent full load hour fraction (Line 6) and enter the resulting quantity in (Line 17A). Multiply (Line 17A) by the peak cooling load (Line 4) to determine the total annual cooling load (ton-hours) and enter this value in (Line 17B).

18. *Energy Requirements for the Electric Chiller Option*. Chiller energy is calculated by multiplying the annual cooling load (Line 17B) by the IPLV of the electric chiller (Line 14A2) then enter this value in (Line 18A). The parasitic energy requirements are calculated by multiplying the peak cooling load (tons) from (Line 4) by the annual operating hours (hrs) from (Line 5) and the electric chiller parasitic power requirements (kW/ton) from (Line 14A3) and entering in (Line 18B). The total annual electric energy requirements are the sum of chiller energy (Line 18A) and the parasitic energy (Line 18B) and enter this value in (Line 18C).

19. *Energy Requirements for the Absorption Chiller Option*. Chiller natural gas is calculated by multiplying the annual cooling load (Line 17B) by a conversion to MBTU (0.012) then dividing by the chiller Coefficient-of-Performance (Line 14B2) then enter this value in 19A. The parasitic electric energy requirements are calculated by multiplying the peak cooling load (tons) from Line 4 by the annual

operating hours (hrs) from (Line 5) and the absorption chiller parasitic power requirements (kW/ton) from (Line 14B3) and entering this value in (Line 19B).

20. *Energy Requirements for the Engine Driven Chiller (without heat recovery) Option.* Chiller natural gas is calculated by multiplying the annual cooling load (Line 17B) by a conversion to MBTU (0.012) then dividing by the chiller Coefficient-of-Performance (Line 14C2) then entering this value in (Line 20A). The parasitic electric energy requirements are calculated by multiplying the parasitic power requirements (kW/ton) from (Line 14C3) and entering this value in (Line 20B).

21. *Energy Requirements for the Engine Driven Chiller (with heat recovery) Option.* Natural gas consumed by the system (chiller and savings from recovered heat) is calculated by determining the fuel consumed by the chiller (Line 20A) and subtracting from that the energy recovered. The recovered energy is calculated by multiplying the annual hours of operation (Line 5) by the available and useful thermal energy (Line 15A), then dividing by the summer boiler efficiency (Line 15B) and multiplying this by a conversion to MBTU (0.000001 MBTU/Btu). The additional natural gas that will be purchased is then entered in Line 21A. The parasitic electric energy requirements are calculated by multiplying the parasitic power requirements (kW/ton) from) Line 14C3) and entering this value in (Line 21B).

Annual Demand Charge Calculations

Calculating the demand charge for each of the different chiller technologies is the most complicated part of the worksheet analysis. It is not difficult but it does require that the analysts do a good job of "bookkeeping" or the likelihood that an erroneous answer increases significantly.

22. *Annual Demand Charge—Electric Chiller Option.*

- The first step in calculating the annual demand charge for the electric chiller option is to copy the Cooling Load Fraction data from (Lines 7A - 7L) to (Lines 22A1 - 22A12), the first column on the electric demand sheet.
- Next, the Cooling Load, in tons, is calculated. This is done by multiplying the Cooling Load Fraction values in column (Line 22A) by the Peak Load (Line 4) and entering these in the corresponding rows of (Lines 22B1 - 22B12).
- The chiller electric demand is then determined. This is done by multiplying the Electric Chiller Efficiency (Line 14A1), in kW/ton, by Cooling Load (Lines 22B1 -

22B12), in tons, to get the demand for the electric chiller. These values are entered in the appropriate rows in of (Lines 22C1 - 22C12).

- Auxiliary power required to operate the chiller evaporator and condenser pumps and the cooling tower fan(s) is now calculated. The appropriate values are obtained by one of two methods: (1) if there is no cooling required during a specific month, the Cooling Load (Lines 22B1 - 22B12) is zero, the Auxiliary Demand (Lines 22D1 - 22D12) is zero; or (2) if cooling is required, the Auxiliary Electrical Requirements (Line 14A3) is multiplied by the Peak Load (Line 4) and this value is entered as the Auxiliary Demand (Lines 22D1 - 22D12). The values entered here are always based on the peak cooling load since the evaporator and condenser pumps must always run when the chiller is operating. While the cooling tower fan can modulate with ambient temperature, it is assumed to operate constantly, making the analysis more conservative (in favor of the electric chiller).
- The Actual Demand (Lines 22E1 - 22E12) is determined by adding the Chiller Demand (Lines 22C1 - 22C12) to the Auxiliary Demand (Lines 22D1 - 22D12) and entering these values in the corresponding rows of the Actual Demand column.
- The Ratchet Demand is calculated by multiplying the maximum value in the Actual Demand (Lines 22E1- 22E12) by the Utility Ratchet (Line 11A), and entering this value in each row of the Ratchet Demand (Lines 22F1 - 22F12). If the rate schedule has no ratchet, enter all zeros in this column.
- The Billed Demand is the greater of the Actual Demand (Lines 22E1 - 22E12) or the Ratchet Demand (Lines 22F1 - 22F12) for each month, even when there is no cooling. These values are entered in the Billed Demand column (Lines 22G1 - 22G12).
- Next, the appropriate utility demand charge, Summer Demand (Line 10A) or Winter Demand (Line 12), is entered as $/kW in the Demand Charge column (Lines 22H1 - 22H12). Be sure to enter the correct values for each month as the demand charge often changes to a higher, summer rate in May or June and the returns to the lower, winter rate in September or October.
- The monthly demand charge resulting from owning and operating the chiller is calculated by multiplying the Billed Demand (Lines 22G1 - 22G12) by the corresponding Demand Charge (Lines 22H1 - 22H12) and entering this value in the Monthly Charge column (Lines 22I1 - 22I12).
- Finally, the total Annual Demand Charge is determined by adding all values in the Monthly Charge column (Lines 22I1 - 22I12). The result is entered in the Total Annual Demand Charge (Line 22I13).

23. *Annual Demand Charge—Absorption Chiller Option.*

- The first step in calculating the annual demand charge for the absorption chiller option is to copy the Cooling Load Fraction data from (Lines 7A - 7L) to (Lines 23A1 - 23A12), the first column on the electric demand sheet.
- Next, the Cooling Load, in tons, is calculated. This is done by multiplying the Cooling Load Fraction values in column (Line 23A) by the Peak Load (Line 4) and entering these in the corresponding rows (Lines 23B1 - 23B12).
- The absorption chiller parasitic electric demand has already been determined from Figure 10 and will be included as part of the Auxiliary Demand in the next column. Therefore, zeroes should be entered in each row of Chiller Demand (Lines 23C1 - 23C12). This column is not used but was left in to maintain consistency with the electric chiller demand charge worksheet.
- Auxiliary power required to operate the chiller evaporator and condenser pumps, the cooling tower fan(s), and absorption chiller parasitic power is now determined. The appropriate values are obtained by one of two methods: (1) if there is no cooling required during a specific month, the Cooling Load (Lines 23B1 - 23B12) is zero, the Auxiliary Demand (Lines 23D1 - 23D12) is zero; or (2) if cooling is required, the value for Auxiliary Electrical Requirements (Line 14B3) is multiplied by the Peak Load (Line 4) and this value is entered as the Auxiliary Demand (Lines 23D1 - 23D12). The values entered here are always based on the peak cooling load since the evaporator and condenser pumps must always run when the chiller is operating. While the cooling tower fan can modulate with ambient temperature, it is assumed to operate constantly, making the analysis somewhat more conservative (in favor of the electric chiller).
- The Actual Demand (Lines 23E1 - 23E12) is determined by adding the Chiller Demand (Lines 23C1 - 23C12) and the Auxiliary Demand (Lines 23D1 - 23D12) and by entering these values in the corresponding rows of the Actual Demand column.
- The Ratchet Demand is calculated by multiplying the maximum value in the Actual Demand (Lines 23E1- 23E12) by the Utility Ratchet (Line 11A) and entering this value in each row of the Ratchet Demand (Lines 23F1 - 23F12). If the rate schedule has no ratchet, enter all zeros in this column.
- The Billed Demand is the greater of the Actual Demand (Lines 23E1 - 23E12) or the Ratchet Demand (Lines 23F1 - 23F12) for each month, even when there is no cooling. These values are entered in the Billed Demand column (Lines 23G1 - 23G12).
- Next the appropriate utility demand charge, Summer Demand (Line 10A) or Winter Demand (Line 12), is entered as $/kW in the Demand Charge column (Lines 23H1 - 23H12). Be sure to enter the correct values for each month as the

demand charge often changes to a higher, summer rate in May or June and the returns to the lower, winter rate in September or October.

- The monthly demand charge resulting from owning and operating the chiller is calculated by multiplying the Billed Demand (Lines 23G1 - 23G12) by the corresponding Demand Charge (Lines 23H1 - 23H12) and entering this value in the Monthly Charge column (Lines 23I1 - 23I12).
- Finally, the total Annual Demand Charge is determined by adding all values in the Monthly Charge column (Lines 23I1 - 23I12). The result is entered in the Total Annual Demand Charge (Line 23I13).

24. *Annual Demand Charge—Engine Driven Chiller Option.*

- The first step in calculating the annual demand charge for the engine driven chiller option is to copy the Cooling Load Fraction data from (Lines 7A - 7L) to (Lines 24A1 - 24A12), the first column on the electric demand sheet.
- Next, the Cooling Load, in tons, is calculated. This is done by multiplying the Cooling Load Fraction values in column (Lines 24A) by the Peak Load (Line 4) and entering these in the corresponding rows (Lines 24B1 - 24B12).
- The engine-driven chiller parasitic electric demand has already been determined form Figure 10 and will be included as part of the Auxiliary Demand in the next column. Therefore zeroes should be entered in each row of Chiller Demand (Lines 24C1 - 24C12). This column is not used, but was left in for consistency with the electric chiller demand charge worksheet.
- Auxiliary power required to operate the chiller evaporator and condenser pumps, the cooling tower fan(s), and engine driven chiller parasitic power is now determined. The appropriate values are obtained by one of two methods: (1) if there is no cooling required during a specific month, the Cooling Load (Lines 24B1 - 24B12) is zero, and the Auxiliary Demand (Lines 24D1 - 24D12) is zero; or (2) if cooling is required, the Auxiliary Electrical Requirements (Line 14C3) is multiplied by the Peak Load (Line 4) and this value is entered as the Auxiliary Demand (Lines 24D1 - 24D12). The values entered here are always based on the peak cooling load since the evaporator and condenser pumps must always run when the chiller is operating. While the cooling tower fan can modulate with ambient temperature, it is assumed to operate constantly, making the analysis somewhat more conservative (in favor of the electric chiller).
- The Actual Demand (Lines 24E1 - 24E12) is determined by adding the Chiller Demand (Lines 24C1 - 24C12) and the Auxiliary Demand (Lines 24D1 - 24D12), and entering these values in the corresponding rows of the Actual Demand column.
- The Ratchet Demand is calculated by multiplying the maximum value in the Actual Demand (Lines 24E1- 24E12) by the Utility Ratchet (Line 11A) and

entering this value in each row of the Ratchet Demand (Lines 24F1 - 24F12). If the rate schedule has no ratchet, enter all zeros in this column.

- The Billed Demand is the greater of the Actual Demand (Lines 24E1 - 24E12) or the Ratchet Demand (Lines 24F1 - 24F12) for each month, even when there is no cooling. These values are entered in the Billed Demand column (Lines 24G1 - 24G12).
- Next, the appropriate utility demand charge, Summer Demand (Line 10A) or Winter Demand (Line 12), is entered as $/kW in the Demand Charge column (Lines 24H1 - 24H12). Be sure to enter the correct values for each month as the demand charge often changes to a higher, summer rate in May or June and the returns to the lower, winter rate in September or October.
- The monthly demand charge resulting from owning and operating the chiller is calculated by multiplying the Billed Demand (Lines 24G1 - 24G12) by the corresponding Demand Charge (Lines 24H1 - 24H12) and entering this value in the Monthly Charge column (Lines 24I1 - 24I12).
- Finally, the total Annual Demand Charge is determined by adding all values in the Monthly Charge column (Lines 24I1 - 24I12). The result is entered in the Total Annual Demand Charge (Line 24I13).

Owning and Operating Costs

Electric Chiller Option

25. *Installed System Cost (Electric Chiller).* To calculate the cost of the installed chiller system, the equipment and installation costs, along with design and SIOH costs must be accounted for. Equipment and installation cost estimates are calculated be adding together the equipment cost per ton (Line 16A1) to the installation cost per ton (Line 16A2), then multiplying this quantity by the chiller capacity (Line 4) and entering the resultant value in (Line 25A).

26. *Energy Costs (Electric Chiller).* To calculate the cost of electricity (energy and demand) for the electric chiller option, enter the cost of electric energy in $/kWh (Line 13) in (Line 26A1) and enter the annual kWh consumed (Line 18C) in (Line 26A2). Multiply (Line 26A1 by (Line 26A2) and enter this value in (Line 26A3). The Discount Factor in obtained from Appendix B or from NIST (October 1994) for the most current values. The data must be selected for the correct geographic region for each fuel type and for electric demand. The Discounted Cost is an estimate of the total cost of electricity, in current year dollars, over the life of the project and is calculated by multiplying the Annual Cost (Line 26A3) by the Discount Factor (Line 26A4) and entering this value in (Line 26A5). Similarly,

the Demand Charge is calculated. The annual demand charge (Line 22I13) is entered in (Line 26C3), along with the appropriate Discount Factor in (Line 26C4). These are multiplied and the product entered in (Line 26C5). The total annual energy cost is calculated by adding the values in (Line 26A3) and (Line 26C3) and entering this total in (Line 26D3). The total Discounted Cost is calculated by adding the values in (Line 26A5) and (Line 26C5) and entering this total in (Line 26D5).

27. *Maintenance Costs (Electric Chiller).* The annual maintenance costs incurred while operating the electric chiller are estimated by multiplying the maintenance cost per ton-hour of cooling (Line 16A3) by the number of ton-hours of cooling produced annually by the chiller (Line 17B), and entering this value in (Line 27A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 27B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 27C).

28. *Make-up Water Costs (Electric Chiller).* The annual make-up water costs incurred while operating the electric chiller are estimated by multiplying the cost of treated water required per ton-hour of cooling (Line 16A4) by the number of ton-hours of cooling produced annually by the chiller (Line 17B) and entering this value in (Line 28A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 28B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 28C).

29. *Total Annual Operating Cost.* The total annual operating cost is calculated by adding together the cost of energy (Line 26D3), maintenance (Line 27A), and make-up water (Line 28A). This value is entered in (Line 29).

30. *Total Discounted Life Cycle Cost.* The total owning and operating cost of the electric chiller is calculated by adding together the installed equipment cost (Line 25E), Discounted Energy Cost (Line 26D5), Discounted Maintenance Cost (Line 27C), and the Discounted Make-up Water Cost (Line 28C). This value is entered in (Line 30).

Absorption Chiller Option

31. *Installed System Cost (Absorption Chiller).* To calculate the cost of the installed chiller system, the equipment and installation costs, along with design and SIOH costs, must be accounted for. Equipment and installation cost estimates are

calculated by adding together the equipment cost per ton (Line 16B1) and the installation cost per ton (Line 16B2), and multiplying this by the chiller capacity (Line 4), then entering this value in (Line 31A).

32. *Energy Costs (Absorption Chiller).* To calculate the cost of electricity (energy and demand) for the absorption chiller option, enter the cost of electric energy in $/kWh, (Line 13) in (Line 32A1) and enter the annual kWh consumed (Line 19B) in (Line 32A2). Multiply (Line 32A1) by (Line 32A2) and enter this value in (Line 32A3). The Discount Factor in obtained from Appendix B or from NIST (October 1994) for the most current values. The data must be selected for the correct geographic region for each fuel type and for electric demand. The Discounted Cost is an estimate of the total cost of electricity, in current year dollars, over the life of the project and is calculated by multiplying the Annual Cost (Line 32A3) by the Discount Factor (Line 32A4), then entering this value in (Line 32A5). The Natural Gas Cost and Demand Charge is calculated similarly. The cost of natural gas (Line 9) is entered in (Line 32B1) and the quantity of natural gas consumed (Line 19A) is entered in (Line 32B2). These are multiplied and the product entered in (Line 32B3). The Discount Factor is obtained as for electricity and is entered in (Line 32B4). The annual natural gas cost is multiplied by the discount factor and the product entered in (Line 32B5). The annual demand charge (Line 23I13) is entered in (Line 32C3) along with the appropriate Discount Factor in (Line 32C4). These are multiplied and the product entered in (Line 32C5). The total annual energy cost is calculated by adding the values in (Line 32A3) through (Line 32C3) and entering this total in (Line 32D3). The total Discounted Cost is calculated by adding the values in (Line 32A5) through (Line 32C5) and entering this total in (Line 32D5).

33. *Maintenance Costs (Absorption Chiller).* The annual maintenance costs incurred while operating the absorption chiller are estimated by multiplying the maintenance cost per ton-hour of cooling (Line 16B3) by the number of ton-hours of cooling produced annually by the chiller (Line 17B), and entering this value in (Line 33A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 33B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 33C).

34. *Make-up Water Costs (Absorption Chiller).* The annual make-up water costs incurred while operating the absorption chiller are estimated by multiplying the cost of treated water required per ton-hour of cooling (Line 16B4) by the number of ton-hours of cooling produced annually by the chiller (Line 17B), and entering this value in (Line 34A). The Discount Factor is obtained from Appendix B or

from NIST (U.S. Dept. of Commerce October 1994) and is entered in (Line 34B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 34C).

35. *Total Annual Operating Cost.* The total annual operating cost for the absorption chiller is calculated by adding together the cost of energy (Line 32D3), maintenance (Line 33A), and make-up water (Line 34A). This value is entered in (Line 35).

36. *Total Discounted Life Cycle Cost.* The total owning and operating cost of the electric chiller is calculated by adding together the installed equipment cost (Line 31E), Discounted Energy Cost (Line 32D5), Discounted Maintenance Cost (Line 33C), and the Discounted Make-up Water Cost (Line 34C). This value is entered in (Line 36).

Engine-Driven Chiller (Without Heat Recovery) Option

37. *Installed System Cost (Engine Driven Chiller without heat recovery).* To calculate the cost of the installed chiller system, the equipment and installation costs, along with design and SIOH costs, must be accounted for. Equipment and installation cost estimates are calculated by adding together the equipment cost per ton (Line 16C1) and the installation cost per ton (Line 16C2) and multiplying this by the chiller capacity (Line 4), then entering this value in (Line 37A).

38. *Energy Costs (Engine Driven Chiller without heat recovery).* To calculate the cost of electricity for the engine driven chiller option, enter the cost of electric energy in $/kWh (Line 13) in (Line 38A1), and enter the annual kWh consumed (Line 20B) in (Line 38A1). Multiply (Line 38A1) by (Line 38A2) and enter this value in (Line 38A3). The Discount Factor in obtained from Appendix B or from NIST (October 1994) for the most current values. The data must be selected for the correct geographic region for each fuel type and for electric demand. The Discounted Cost is an estimate of the total cost of electricity, in current year dollars, over the life of the project and is calculated by multiplying the Annual Cost (Line 38A3) by the Discount Factor (Line 38A4) and entering this value in (Line 38A5). The Natural Gas Cost and Demand Charge is calculated similarly. The cost of natural gas (Line 9) is entered in (Line 38B1) and the quantity of natural gas consumed (Line 20A) is entered in (Line 38B2). These are multiplied and the product is entered in (Line 38B3). The Discount Factor is obtained as for electricity and is entered in (Line 38B4). The annual natural gas cost is multiplied by the discount factor and the product entered in (Line 38B5). The annual demand charge (Line 24I13) is entered in (Line 38C3), along with the

appropriate Discount Factor in (Line 38C4). These are multiplied and the product is entered in (Line 38C5). The total annual energy cost is calculated by adding the values in (Line 38A3) through (Line 38C3), and entering this total in (Line 38D3). The total Discounted Cost is calculated by adding the values in (Line 38A5) through (Line 38C5), and entering this total in (Line 38D5).

39. *Maintenance Costs (Engine Driven Chiller w/o heat recovery).* The annual maintenance costs incurred while operating the engine driven chiller are estimated by multiplying the maintenance cost per ton-hour of cooling (Line 16C3) by the number of ton-hours of cooling produced annually by the chiller (Line 17B) and entering this value in (Line 39A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 39B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 39C).

40. *Make-up Water Costs (Engine Driven Chiller without heat recovery).* The annual make-up water costs incurred while operating the electric chiller are estimated by multiplying the cost of treated water required per ton-hour of cooling (Line 16C4) by the number of ton-hours of cooling produced annually by the chiller (Line 17B) and entering this value in (Line 40A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 40B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 40C).

41. *Total Annual Operating Cost.* The total annual operating cost is calculated by adding together the cost of energy (Line 38D3), maintenance (Line 39A), and make-up water (Line 40A). This value is entered in (Line 41).

42. *Total Discounted Life Cycle Cost.* The total owning and operating cost of the electric chiller is calculated by adding together the installed equipment cost (Line 37E), Discounted Energy Cost (Line 38D5), Discounted Maintenance Cost (Line 39C), and the Discounted Make-up Water Cost (Line 40C). This value is entered in (Line 42).

Engine-Driven Chiller (w/ Heat Recovery) Option

43. *Installed System Cost (Engine Driven Chiller With Heat Recovery).* To calculate the cost of the installed chiller system, the equipment and installation costs, along with design and SIOH costs, must be accounted for. Equipment and installation cost estimates are calculated by adding together the equipment cost

per ton (Line 16D1) and the installation cost per ton (Line 16D2), multiplying this by the chiller capacity (Line 4), then entering this value in (Line 43A).

44. *Energy Costs (Engine Driven Chiller With Heat Recovery).* To calculate the cost of electricity for the engine driven chiller option, enter the cost of electric energy in $/kWh (Line 13) in (Line 44A1), enter the annual kWh consumed (Line 21B) in (Line 44A2). Multiply (Line 44A1) by (Line 44A2) and enter this value in (Line 44A3). The Discount Factor in obtained from Appendix B or from NIST (October 1994) for the most current values. The data must be selected for the correct geographic region for each fuel type and for electric demand. The Discounted Cost is an estimate of the total cost of electricity, in current year dollars, over the life of the project and is calculated by multiplying the Annual Cost (Line 44A3) by the Discount Factor (Line 44A4) and entering this value in (Line 44A5). The Natural Gas Cost and Demand Charge is calculated similarly. The cost of natural gas (Line 9) is entered in (Line 44B1) and the quantity of natural gas consumed (Line 21A) is entered in (Line 44B2). These are multiplied and the product entered in (Line 44B3). The Discount Factor is obtained as for electricity and entered in (Line 44B4). The annual natural gas cost is multiplied by the discount factor and the product is entered in (Line 44B5). The annual demand charge (Line 24I13) is entered in (Line 44C3), along with the appropriate Discount Factor in (Line 38C4). These are multiplied and the product is entered in (Line 44C5). The total annual energy cost is calculated by adding the values in (Line 44A3) through (Line 44C3) and entering this total in (Line 44D3). The total Discounted Cost is calculated by adding the values in (Line 44A5) through (Line 44C5) and entering this total in (Line 44D5).

45. *Maintenance Costs (Engine Driven Chiller With Heat Recovery).* The annual maintenance costs incurred while operating the electric chiller are estimated by multiplying the maintenance cost per ton-hour of cooling (Line 16D3) by the number of ton-hours of cooling produced annually by the chiller (Line 17B), and entering this value in (Line 45A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 45B). The Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 45C).

46. *Make-up Water Costs (Engine Driven Chiller With Heat Recovery).* The annual make-up water costs incurred while operating the electric chiller are estimated by multiplying the cost of treated water required per ton-hour of cooling (Line 16D4) by the number of ton-hours of cooling produced annually by the chiller (Line 17B) and entering this value in (Line 46A). The Discount Factor is obtained from Appendix B or from NIST and is entered in (Line 46B). The

Discounted Cost is determined by multiplying the annual maintenance cost by the discount factor and entering this value in (Line 46C).

47. *Total Annual Operating Cost.* The total annual operating cost is calculated by adding together the cost of energy (Line 44D3), maintenance (Line 45A), and make-up water (Line 46A). This value is entered in (Line 47).

48. *Total Discounted Life Cycle Cost.* The total owning and operating cost of the electric chiller is calculated by adding together the installed equipment cost (Line 43E), Discounted Energy Cost (Line 44D5), Discounted Maintenance Cost (Line 45C), and the Discounted Make-up Water Cost (Line 46C). This value is entered in (Line 48).

Incremental Savings-to-Investment Ratio

49. *Compare Absorption Chiller to Electric Chiller.* To calculate the incremental SIR for the absorption chiller, compared to an electric chiller, subtract from the Total Discounted Life Cycle Cost of the electric chiller (Line 30) that of the absorption chiller (Line 36); divide this quantity by the difference in cost of the absorption chiller (Line 31E) and the electric chiller (Line 25E), then enter this value in (Line 49).

50. *Compare Engine Driven Chiller (Without Heat Recovery) to Electric Chiller.* To calculate the incremental SIR for the engine driven chiller w/o heat recovery, compared to an electric chiller, subtract from the Total Discounted Life Cycle Cost of the electric chiller (Line 30) that of the engine driven chiller w/o heat recovery (Line 42); divide this quantity by the difference in cost of the absorption chiller (Line 37E) and the electric chiller (Line 25E), then enter this value in (Line 50).

51. *Compare Engine Driven Chiller (With Heat Recovery) to Electric Chiller.* To calculate the incremental SIR for the engine driven chiller w/ heat recovery, compared to an electric chiller, subtract from the Total Discounted Life Cycle Cost of the electric chiller (Line 30) that of the engine driven chiller w/ heat recovery (Line 48); divide this by the difference in cost of the absorption chiller (Line 43E) and the electric chiller(Line 25E), then enter this value in (Line 51).

Incremental Simple Payback Period

52. *Compare Absorption Chiller to Electric Chiller.* To calculate the incremental simple payback for the absorption chiller, compared to an electric chiller, subtract from the Total Investment for the absorption chiller (Line 31E) that of the electric chiller (Line 25E); divide this by the difference in Total Annual Operating Cost of the Electric Chiller (Line 29) minus the Total Annual Operating Cost of the Absorption Chiller (Line 35), then enter this value in (Line 52).

53. *Compare Engine Driven Chiller (Without Heat Recovery) to Electric Chiller.* To calculate the incremental simple payback for the engine driven chiller w/o heat recovery, compared to an electric chiller, subtract from the Total Investment for the engine driven chiller w/o heat recovery (Line 37E) that of the electric chiller (Line 25E); divide this by the difference in Total Annual Operating Cost of the Electric Chiller (Line 29) minus the Total Annual Operating Cost of the Engine Driven Chiller w/o heat recovery (Line 41), then enter this value in (Line 53).

54. *Compare Engine Driven Chiller (With Heat Recovery) to Electric Chiller.* To calculate the incremental simple payback for the engine driven chiller w/ heat recovery, compared to an electric chiller, subtract from the Total Investment for the engine driven chiller w/ heat recovery (Line 43E) that of the electric chiller (Line 25E); divide this by the difference in Total Annual Operating Cost of the Electric Chiller (Line 29) minus the Total Annual Operating Cost of the Engine Driven Chiller w/ heat recovery (Line 47), then enter this value in (Line 54).

Evaluation Worksheet Example

The following filled-in worksheet gives an example for the user, indicating the flow of information from top to bottom. This sample worksheet does not represent a specific site, although the information used are reasonable values for a wide range of electric and gas utilities, cooling equipment performance, and cooling loads. Census Region 2 was used to determine the Discount Factor for fuel consumption over the 25 year life of the equipment. Information in ***Bold Italics*** is that which is provided, or calculated, by the user.

1. Facility Name: ***TEST SITE*** 2. Date: ***Today***
3. Prepared by: ***The User***

COOLING LOAD

4. Peak Load (or installed chiller capacity) ***500*** tons
5. Hours of Annual Operation (hr/day * days/cooling season) ***4000*** hrs
6. Equivalent Full Load Hour fraction (enter as a fraction [0.00]) ***0.60***

7. Monthly Peak Cooling Load (Fraction of Peak Load - [0.00])

A. Jan	***0.00***	B. Feb	***0.00***	C. Mar	***0.0***	D. Apr	***0.25***
E. May	***0.60***	F. Jun	***0.80***	G. Jul	***1.00***	H. Aug	***1.00***
I. Sep	***0.80***	J. Oct	***0.25***	K. Nov	***0.00***	L. Dec	***0.00***

UTILITY RATES

8. Utility Rebates
   A. Electric Utility $ ***0*** /ton
   B. Gas Utility $ ***100*** /ton

9. Natural Gas
   Cooling Gas Rate: $ ***3.00*** /MBtu

Electricity	(A)		(B)		(C)
10. Summer Demand:	$ ***16.00***	/kW from	***June***	through	***September***
11. Ratchet [0.00]:	***0.85***	fraction from	***January***	through	***December***
12. Winter Demand:	$ ***12.00***	/kW			
13. Energy:	$ ***0.035***	/kWh			

COOLING EQUIPMENT PERFORMANCE

14. Cooling Equipment Energy requirements (see Figures 7, 8, 9, & 13)

	Chiller Efficiency Peak (1)	Chiller Efficiency IPLV (2)		Auxiliary Electrical Requirements (3)	
A. New Electric:	***0.60***	***0.55***	kW/ton	***0.22***	kW/ton
B. Absorption:	***1.05***	***1.10***	COP	***0.29***	kW/ton
C. Engine Driven:	***1.50***	***1.70***	COP	***0.24***	kW/ton

15. Heat Recovery (Engine Driven Chiller only)
    A. Usable Thermal Energy: ***400,000*** Btu/hr
    B. Summer Boiler Efficiency: ***0.80*** fraction [0.00]

Figure 14. Sample evaluation worksheet.

16. Equipment and Maintenance Costs (see Figures 4 & 6 and Tables 1 & 2)

	Chiller (1)	Installation (2)	Maintenance (3)	Make-up Water (4)
A. Electric:	$ *310* /ton	$ *275* /ton	$ *0.006* /t-h	$ *0.016* /t-h
B. Absorption:	$ *510* /ton	$ *275* /ton	$ *0.008* /t-h	$ *0.025* /t-h
Engine Driven:				
C. without HR:	$ *530* /ton	$ *300* /ton	$ *0.015* /t-h	$ *0.017* /t-h
D. with HR:	$ *540* /ton	$ *325* /ton	$ *0.016* /t-h	$ *0.017* /t-h

17. Cooling Hours
   A. Annual Equivalent Full Load Hours (5 * 6) — *2400* EFLH/yr
   B. Annual Cooling Load (17A * 4) — *1,200,000* t-h/yr

Energy Consumption (Chiller + Parasitics)

18. A. Electric Chiller Energy (17B * 14A2) — *660,000* kWh
   B. Auxiliary Energy (4 * 5 * 14A3) — *440,000* kWh
   C. Total Electricity (18A +18B) — *1100,000* kWh

19. A. Absorption Chiller Gas (17B * 0.012 / 14B2) — *13,091* MBtu
   B. Auxiliary Energy (4 * 5 * 14B3) — *580,000* kWh

20. Engine Driven Chiller w/o heat recovery
   A. Engine Chiller Gas (17 B * 0.012 / 14C2) — *8,471* MBtu
   B. Auxiliary Energy (4 * 5 * 14C3) — *480,000* kWh

21. Engine Driven Chiller w/ heat recovery
   A. Engine Chiller Gas (20A - 0.000001 * 5 * 15A / 15B) — *6,471* MBtu
   B. Auxiliary Energy (4 * 5 * 14C3) — *480,000* kWh

Figure 14. Sample evaluation worksheet (cont'd.).

22. Annual Demand Charge - **Electric Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 * 22A)	Chiller Demand (kW) (14A1 * 22B)	Auxiliary Demand (kW) 0 or (4 * 14A3)	Actual Demand (22C + 22D)	Ratchet Demand (kW) (max{22E} * 11A)	Billed Demand (kW) (max{22E:22F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (22G * 22H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan	*0.00*	*0*	*0*	*0*	*0*	*349*	*349*	*12*	*4188*
2	Feb	*0.00*	*0*	*0*	*0*	*0*	*349*	*349*	*12*	*4188*
3	Mar	*0.00*	*0*	*0*	*0*	*0*	*349*	*349*	*12*	*4188*
4	Apr	*0.25*	*125*	*75*	*110*	*185*	*349*	*349*	*12*	*4188*
5	May	*0.60*	*300*	*180*	*110*	*290*	*349*	*349*	*12*	*4188*
6	Jun	*0.80*	*400*	*240*	*110*	*350*	*349*	*350*	*16*	*5600*
7	Jul	*1.00*	*500*	*300*	*110*	*410*	*349*	*410*	*16*	*6560*
8	Aug	*1.00*	*500*	*300*	*110*	*410*	*349*	*410*	*16*	*6560*
9	Sep	*0.80*	*400*	*240*	*110*	*350*	*349*	*350*	*16*	*5600*
10	Oct	*0.25*	*125*	*75*	*110*	*185*	*349*	*349*	*12*	*4188*
11	Nov	*0.00*	*0*	*0*	*0*	*0*	*349*	*349*	*12*	*4188*
12	Dec	*0.00*	*0*	*0*	*0*	*0*	*349*	*349*	*12*	*4188*
13	Total Annual Demand Charge (sum{22I1:22I12})									*$57,824*

Figure 14. Sample evaluation worksheet (cont'd.).

23. Annual Demand Charge - **Absorption Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 * 23A)	Gas Chiller Demand (kW)	Auxiliary Demand (kW) 0 or (4 * 14B3)	Actual Demand (23C + 23D)	Ratchet Demand (kW) (max{23E} * 11A)	Billed Demand (kW) (max{23E:23F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (23G * 23H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan	*0.00*	*0*	*0*	*0*	*0*	*123*	*123*	*12*	*1476*
2	Feb	*0.00*	*0*	*0*	*0*	*0*	*123*	*123*	*12*	*1476*
3	Mar	*0.00*	*0*	*0*	*0*	*0*	*123*	*123*	*12*	*1476*
4	Apr	*0.25*	*125*	*0*	*145*	*145*	*123*	*145*	*12*	*1740*
5	May	*0.60*	*300*	*0*	*145*	*145*	*123*	*145*	*12*	*1740*
6	Jun	*0.80*	*400*	*0*	*145*	*145*	*123*	*145*	*16*	*2320*
7	Jul	*1.00*	*500*	*0*	*145*	*145*	*123*	*145*	*16*	*2320*
8	Aug	*1.00*	*500*	*0*	*145*	*145*	*123*	*145*	*16*	*2320*
9	Sep	*0.80*	*400*	*0*	*145*	*145*	*123*	*145*	*16*	*2320*
10	Oct	*0.25*	*125*	*0*	*145*	*145*	*123*	*145*	*12*	*1740*
11	Nov	*0.00*	*0*	*0*	*0*	*0*	*123*	*123*	*12*	*1476*
12	Dec	*0.00*	*0*	*0*	*0*	*0*	*123*	*123*	*12*	*1476*
13	Total Annual Demand Charge (sum{23I1:23I12})									*$21,880*

Figure 14. Sample evaluation worksheet (cont'd.).

24. Annual Demand Charge - **Engine Driven Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 * 24A)	Gas Chiller Demand (kW)	Auxiliary Demand (kW) 0 or (4 * 14C3)	Actual Demand (24C + 24D)	Ratchet Demand (kW) (max{24E} * 11A)	Billed Demand (kW) (max{24E:24F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (24G * 24H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan	0.00	0	0	0	0	102	102	12	1224
2	Feb	0.00	0	0	0	0	102	102	12	1224
3	Mar	0.00	0	0	0	0	102	102	12	1224
4	Apr	0.25	125	0	120	120	102	120	12	1440
5	May	0.60	300	0	120	120	102	120	12	1440
6	Jun	0.80	400	0	120	120	102	120	16	1920
7	Jul	1.00	500	0	120	120	102	120	16	1920
8	Aug	1.00	500	0	120	120	102	120	16	1920
9	Sep	0.80	400	0	120	120	102	120	16	1920
10	Oct	0.25	125	0	120	120	102	120	12	1440
11	Nov	0.00	0	0	0	0	102	102	12	1224
12	Dec	0.00	0	0	0	0	102	102	12	1224
13	Total Annual Demand Charge (sum(24I1:24I12))									$18,120

Figure 14. Sample evaluation worksheet (cont'd.).

Owning and Operating Costs - **Electric Chiller Option**

25. Installed System Cost (Electric Chiller)

A. Construction Costs ({16A1 + 16A2} * 4)		$ 292,500
B. SIOH	(25A * 0.055)	$ 16,087
C. Design	(25A * 0.060)	$ 17,550
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$
E. Total Investment (25A + 25B + 25C - 25D)		$ 326,137

26. Energy Costs (Electric Chiller) - obtain Discount Factor from Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Discounted Cost (5)
A. Electricity	$ 0.035 /kWh	1100000 kWh	$ 38,500	18.9	$ 727,650
B. Nat Gas	$ /MBtu	MBtu	$		$
C. Demand			$ 57,824	17.4	$ 1,006,138
D. Total Operating Cost			$ 96,324		$ 1,733,788

27. Maintenance Costs (Electric Chiller)

A. Annual Maint Cost (17B * 16A3)	$ 7,200		
B. Discount Factor (Appendix B)		17.4	
C. Discounted Maintenance Cost (27A * 27B)			$ 125,280

28. Make-up Water Cost (Electric Chiller)

A. Annual Water Cost (17B * 16A4)	$ 19,200		
B. Discount Factor (Appendix B)		17.4	
C. Discounted Maintenance Cost (28A * 28B)			$ 334,080

29. Total Annual Operating Cost (26D3 + 27A + 28A) $ 122,724

30. Total Discounted Life Cycle Cost (25E + 26D5 + 27C + 28C) $ 2,519,285

Figure 14. Sample evaluation worksheet (cont'd.).

Owning and Operating Costs - **Absorption Chiller Option**

31. Installed System Cost (Absorption Chiller)

A. Construction Costs ({16B1 + 16B2} * 4)		$ *392,500*
B. SIOH	(31A * 0.055)	$ *21,588*
C. Design	(31A * 0.060)	$ *23,550*
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$ *50,000*
E. Total Investment (31A + 31B + 31C - 31D)		$ *387,638*

32. Energy Costs (Absorption Chiller) - obtain Discount Factor from Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Discounted Cost (5)
A. Electricity	$ *0.035* /kWh	*580000* kWh	$ *20,300*	*18.9*	$ *383,670*
B. Nat Gas	$ *3.00* /MBtu	*13091* MBtu	$ *39,273*	*22.4*	$ *879,715*
C. Demand			$ *21,880*	*17.4*	$ *380,712*
D. Total Operating Cost			$ *81,453*		$ *1,644,097*

33. Maintenance Costs (Absorption Chiller)

A. Annual Maint Cost (17B * 16B3)	$ *9,600*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (33A * 33B)			$ *167,040*

34. Make-up Water Cost (Absorption Chiller)

A. Annual Water Cost (17B * 16B4)	$ *30,000*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (34A * 34B)			$ *522,000*

35. Total Annual Operating Cost (32D3 + 33A + 34A) $ *121,053*

36. Total Discounted Life Cycle Cost (31E + 32D5 + 33C + 34C) $ *2,720,775*

Figure 14. Sample evaluation worksheet (cont'd.).

Owning and Operating Costs - **Engine Driven Chiller (w/o heat recovery) Option**

37. Installed System Cost (Engine Driven Chiller - w/o heat recovery)

A. Construction Costs ({16C1 + 16C2} * 4)		$ *415,000*
B. SIOH	(37A * 0.055)	$ *22,825*
C. Design	(37A * 0.060)	$ *24,900*
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$ *50,000*
E. Total Investment (37A + 37B + 37C - 37D)		$ *412,725*

38. Energy Costs (Engine Driven Chiller - w/o heat recovery) - Discount Factor in Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Discounted Cost (5)
A. Electricity	$ *0.035* /kWh	*480000* kWh	$ *16,800*	*18.9*	$ *317,520*
B. Nat Gas	$ *3.00* /MBtu	*8471* MBtu	$ *25,413*	*22.4*	$ *569,251*
C. Demand			$ *18,120*	*17.4*	$ *315,288*
D. Total Operating Cost			$ *60,333*		$ *1,202,059*

39. Maintenance Costs (Engine Driven Chiller - w/o heat recovery)

A. Annual Maint Cost (17B * 16C3)	$ *18,000*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (39A * 39B)			$ *313,200*

40. Make-up Water Cost (Engine Driven Chiller - w/o heat recovery)

A. Annual Water Cost (17B * 16C4)	$ *20,400*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (40A * 40B)			$ *354,960*

41. Total Annual Operating Cost (38D3 + 39A + 40A) $ *98,733*

42. Total Discounted Life Cycle Cost (37E + 38D5 + 39C + 40C) $ *2,282,944*

Figure 14. Sample evaluation worksheet (cont'd.).

Owning and Operating Costs - **Engine Driven Chiller (w/ heat recovery) Option**

43. Installed System Cost (Engine Driven Chiller - w/ heat recovery)

A. Construction Costs ({16D1 + 16D2} * 4)		$ *432,500*
B. SIOH	(43A * 0.055)	$ *23,788*
C. Design	(43A * 0.060)	$ *25,950*
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$ *50,000*
E. Total Investment (43A + 43B + 43C - 43D)		$ *432,238*

44. Energy Costs (Engine Driven Chiller - w/ heat recovery) - Discount Factor in Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Discounted Cost (5)
A. Electricity	$ *0.035* /kWh	*480000* kWh	$ *16,800*	*18.9*	$ *317,520*
B. Nat Gas	$ *3.00* /MBtu	*6471* MBtu	$ *19,413*	*22.4*	$ *434,851*
C. Demand			$ *18,120*	*17.4*	$ *315,288*
D. Total Operating Cost			$ *54,333*		$ *1,067,659*

45. Maintenance Costs (Engine Driven Chiller - w/ heat recovery)

A. Annual Maint Cost (17B * 16D3)	$ *19,200*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (45A * 45B)			$ *334,080*

46. Make-up Water Cost (Engine Driven Chiller - w/ heat recovery)

A. Annual Water Cost (17B * 16D4)	$ *20,400*		
B. Discount Factor (Appendix B)		*17.4*	
C. Discounted Maintenance Cost (46A * 46B)			$ *354,960*

47. Total Annual Operating Cost (44D3 + 45A + 46A) $ *93,933*

48. Total Discounted Life Cycle Cost (43E + 44D5 + 45C + 46C) $ *2,188,937*

Figure 14. Sample evaluation worksheet (cont'd.).

Incremental Savings-to-Investment Ratio

49. Compare Absorption Chiller to Electric Chiller
(30 - 36) /(31E - 25E)

(2,519,285 - 2,720,775)
(387,638 - 326,137) SIR = *negative*

50 Compare Engine Driven Chiller (w/o heat recovery) to Electric Chiller
(30 - 42) / (37E - 25E)

(2,519,285 - 2,282,944)
(412,725 - 326,137) SIR = *2.7*

51 Compare Engine Driven Chiller (w/ heat recovery) to Electric Chiller
(30 - 48) / (43E - 25E)

(2,519,285 - 2,188,937)
(432,238 - 326,137) SIR = *3.1*

Incremental Simple Payback Period

52 Compare Absorption Chiller to Electric Chiller
(31E - 25E) / (29 - 35)

(387,638 - 326,137)
(122,724 - 121,053) SP = *36.8* yrs

53 Compare Engine Driven Chiller (w/o heat recovery) to Electric Chiller
(37E - 25E) / (29 - 41)

(412,725 - 326,137)
(122,724 - 98,733) SP = *3.6* yrs

54 Compare Engine Driven Chiller (w/ heat recovery) to Electric Chiller
(43E - 25E) / (29 - 47)

(432,238 - 326,137)
(122,724 - 93,933) SP = *3.7* yrs

Figure 14. Sample evaluation worksheet (cont'd.).

Summary of Example Results

The above example indicates that, for the specific set of utility rates, equipment, and installation costs, the lowest life cycle cost option would be the installation of an engine driven chiller w/ heat recovery, assuming that the specified amount of thermal energy can be used. The next best option would be the engine driven chiller without any heat recovery, followed by the electric chiller option. The absorption chiller would be the most expensive option in this situation.

Table 3 summarizes the economic results of this example and indicates the relative costs and benefits of each cooling technology. The data show that the EDC with heat recovery is, in this example, the lowest life cycle cost option, resulting in significant savings over the "conventional" electric chiller. The annual operating cost of the EDC with heat recovery are 24 percent lower than the electric chiller and the life-cycle cost for the EDC without heat recovery is about 20 percent lower than the electric chiller.

Table 3. Comparison of example chiller economic results.

Economic Parameter	Electric	Absorption	EDC w/o	EDC w/
Initial Cost	$326,137	$387,118	$412,725	$432,238
Annual Operating Cost	$122,724	$121,053	$98,733	$93,933
Life Cycle Cost	$2,519,285	$2,720,775	$2,282,944	$2,188,937
SIR	base	negative	2.7	3.1
Simple Payback	base	never	3.6 yr	3.7 yr

Figure 15 gives breakdown of annual operating costs for each cooling technology. Other than for the electric chiller, which does not require natural gas, each column shows the cost of each component of the annual cost. Included in this is the cost of natural gas, electric energy and demand, maintenance, and make-up water. It is clear that the electric demand is significantly reduced in each of the gas cooling technologies. This is one of the main benefits of these technologies. Also, switching to gas cooling can reduce or eliminate the need to upgrade the electrical system.

On the downside, one can see that the lowest annual fuel cost is the EDC, but this technology also has the highest maintenance requirements. In a time of reduced maintenance personnel, it has becomes more important than ever to consider contracting the service for EDCs. Maintenance costs range from 6 percent (electric chiller) to about 18 percent (EDC) of the annual operating cost. This higher percentage is because a somewhat higher maintenance cost is based on the smaller operating cost of the EDC whereas the smaller maintenance cost of the electric chiller is compared to the larger annual operating cost. As stated earlier, the EDC in this example has the lowest annual operating cost and highest maintenance costs. This

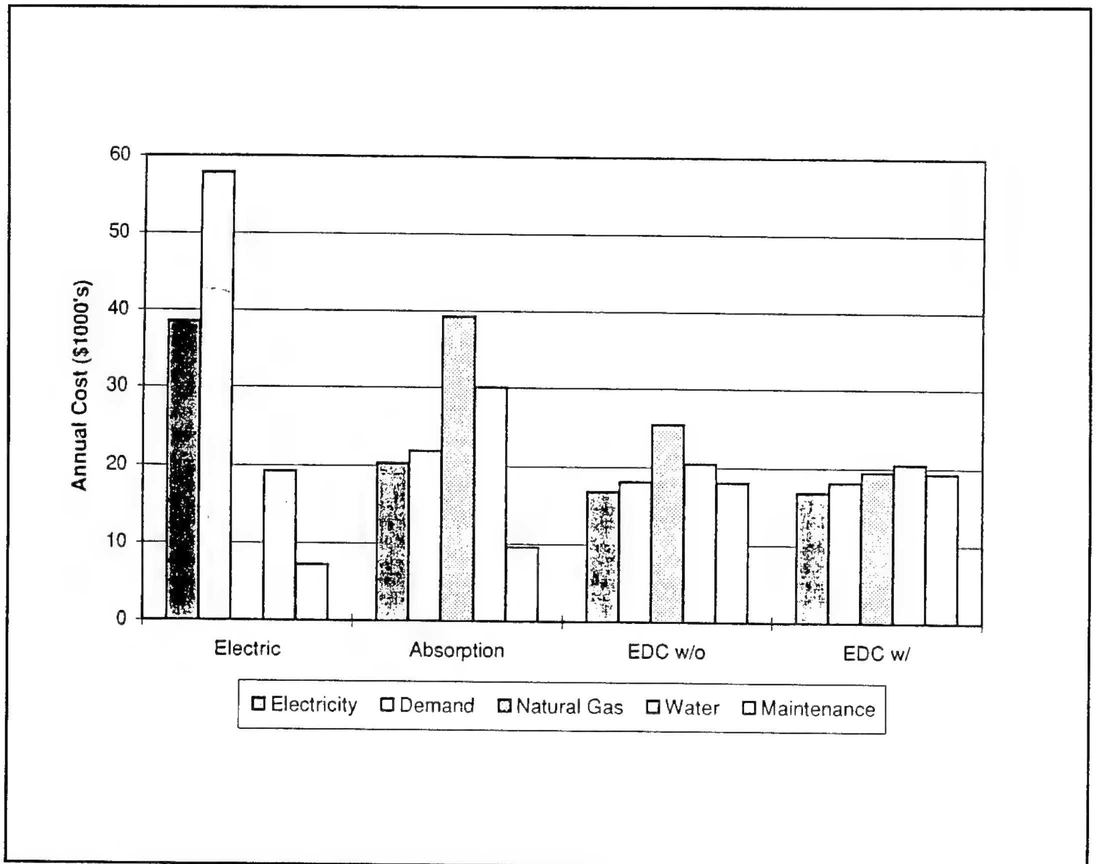

Figure 15. Example annual operating cost breakdown.

results in an—apparently—disproportionately high percentage of the operating cost being spent on maintenance.

Gas cooling technologies typically require more cooling tower make-up water than their electric counterparts. If the engine water jacket of an EDC does not use a separate radiator for engine cooling, an EDC will require less than 10 percent more water than an electric chiller. Absorption chillers may require up to 50 percent more water than an electric chiller.

5 Energy and Environmental Issues

DOD Fixed Facility Energy Use

The following sections give a brief overview of fixed facility energy consumption by the U.S. Department of Defense. The data provided is for electricity, natural gas, fuel oil, and coal, liquefied petroleum gas (LPG) and purchased steam.

Fixed Facility Energy Consumption

DOD energy use information is tracked through the Defense Energy Information System (DEIS), which was established to obtain energy consumption, inventory, and cost data from each of the services. DEIS includes all purchased and nonpurchased energy consumption, except nuclear. DEIS information is typically used by installations and major commands to evaluate trends and determine progress towards meeting energy reduction goals.

Figure 16 shows the DOD overall annual consumption of the primary heating fuels and electricity for fiscal year 1991 (FY91) for facilities located in the Continental United States (CONUS). It shows that the three major DOD organizations, Army, Air Force, and Navy (including Marines) consume roughly equal amounts of energy for their fixed facilities. The proportions of fuel types are also similar, with the exception of the Air Force, which consumes more natural gas and less fuel oil than the other two services. The Army, Air Force, and Navy have each experienced reductions in energy consumption on a MBtu/ksf basis from the 1985 baseline. However, all have experienced increases in electricity consumption, which have led to an overall increase in energy costs. Since 1985, natural gas consumption has remained fairly stable.

Figure 17 shows the DOD energy consumption by source. Electricity and natural gas consumption are nearly equal, and each is more than double the consumption of either fuel oil or coal. Electricity and natural gas account for about 35 and 37 percent, respectively, while all other fuel types account for the remaining fraction and are divided as: fuel oil (15 percent); coal (9 percent); steam (3 percent); and LPG (1 percent), on a Btu basis (Figure 18).

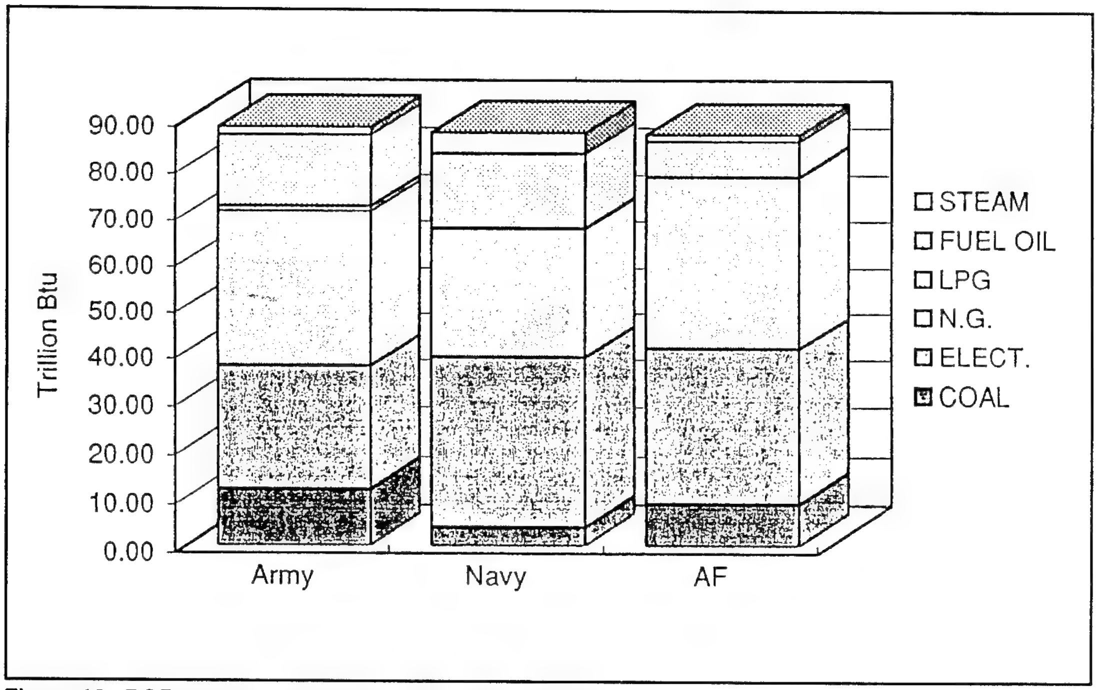

Figure 16. DOD energy consumption for FY91, CONUS.

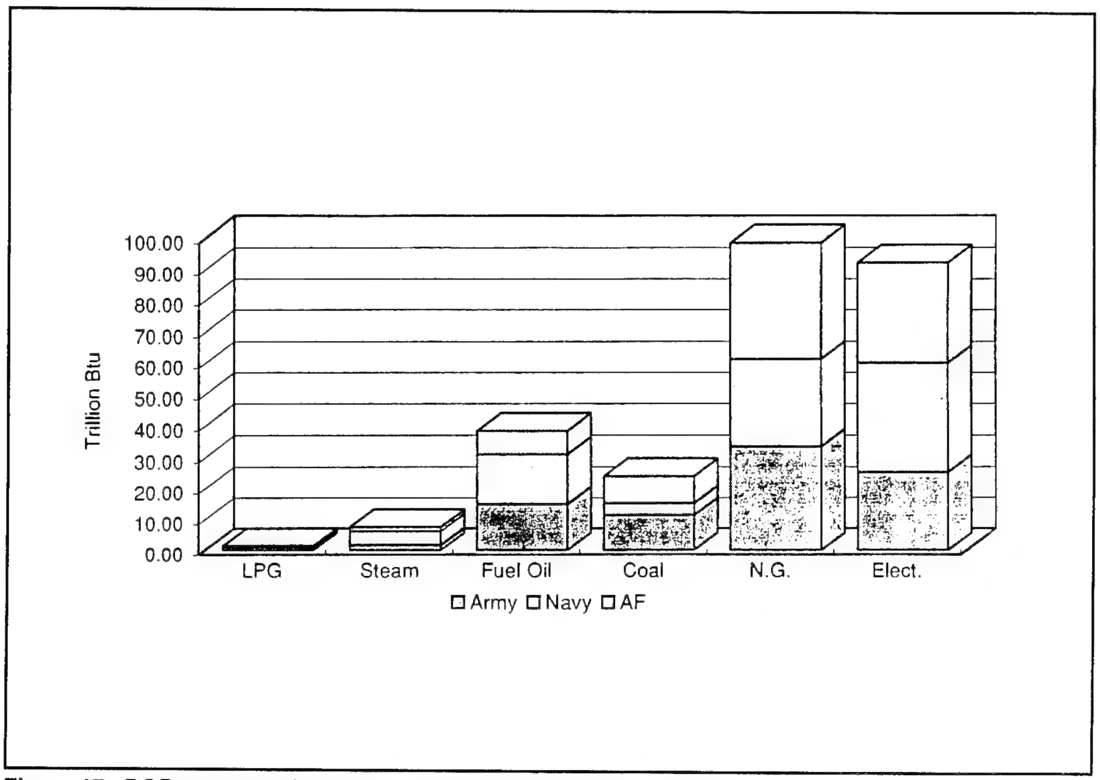

Figure 17. DOD sources of energy consumption for FY91, CONUS.

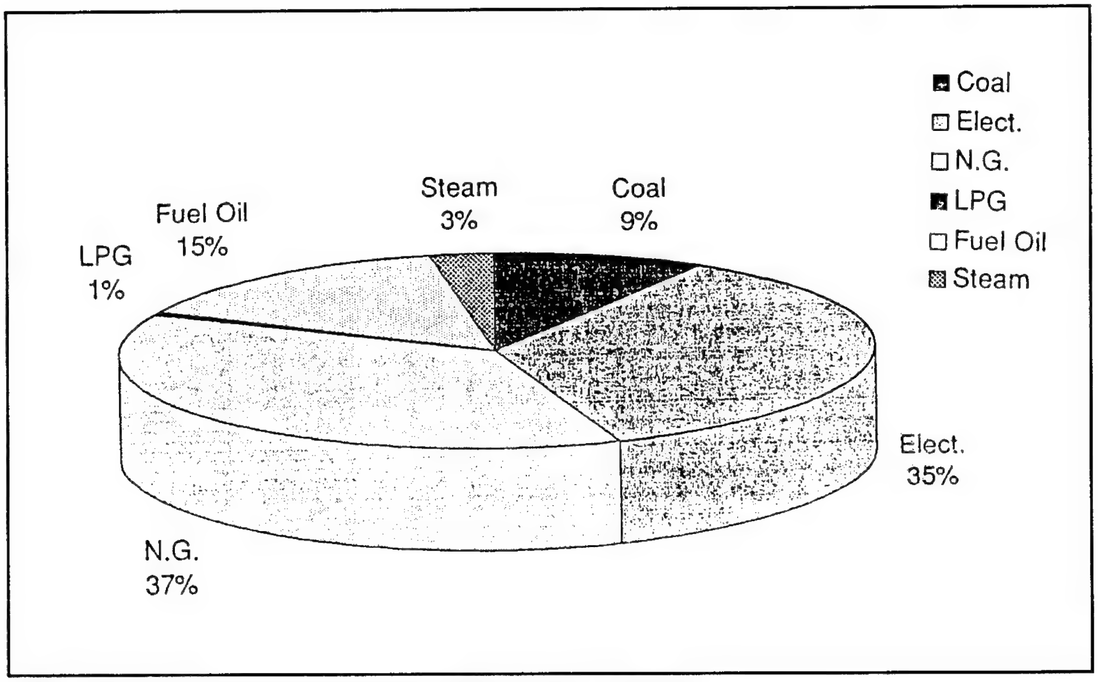

Figure 18. DOD energy consumption fraction for FY91, CONUS.

Fixed Facility Energy Costs

Figures 19, 20, and 21 show the total cost by fuel type, total cost by service, and average cost per MBtu, respectively, for each energy source. Figures 17 and 18 each account for similar amounts of electricity and natural gas energy consumed, 35 and 37 percent respectively, but electricity accounts for about 70 percent of the total fixed facility energy costs, while natural gas accounts for less than 20 percent. In other words, electricity is over four times more expensive than natural gas (Figure 21). It is apparent that, where other technologies are appropriate, electricity should not be the first choice when selecting fuels, especially for heating. While on a Btu basis, coal is the least expensive fuel type, note that coal has substantial costs associated with handling and boiler plant operations.

Applications of new natural gas technologies, both conventional and advanced, could reduce DOD energy costs by improving efficiency of existing natural gas systems, converting more expensive fuel technologies to natural gas, applying new technologies, and developing electrical generation capabilities. Despite the energy conservation efforts of the late 1980's and early 1990's, DOD energy costs are escalating. Note that, in the above sections, only fuel costs were discussed. Any economic analysis comparing alternative technologies must be made on a life-cycle cost basis, including all capital equipment investments and operations, and maintenance costs—not just on fuel costs.

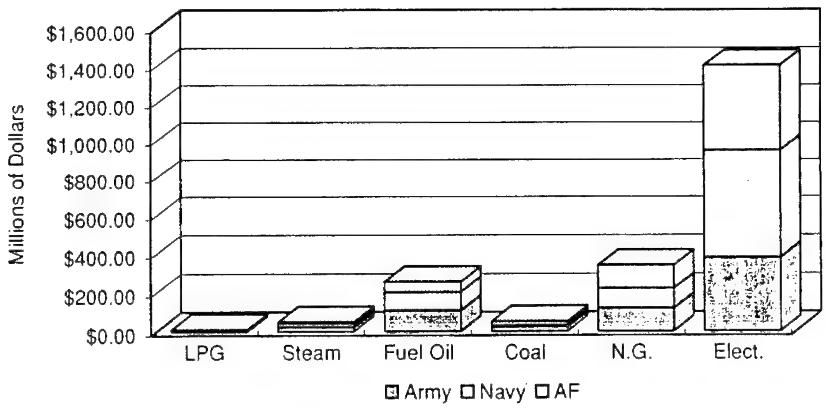

Figure 19. DOD total energy costs by fuel type for FY91, CONUS.

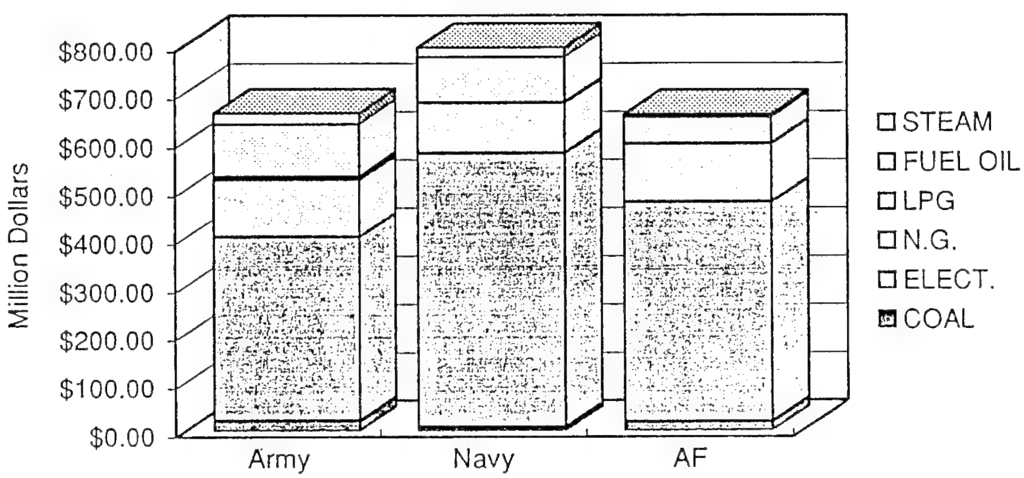

Figure 20. DOD total energy costs by service for FY91, CONUS.

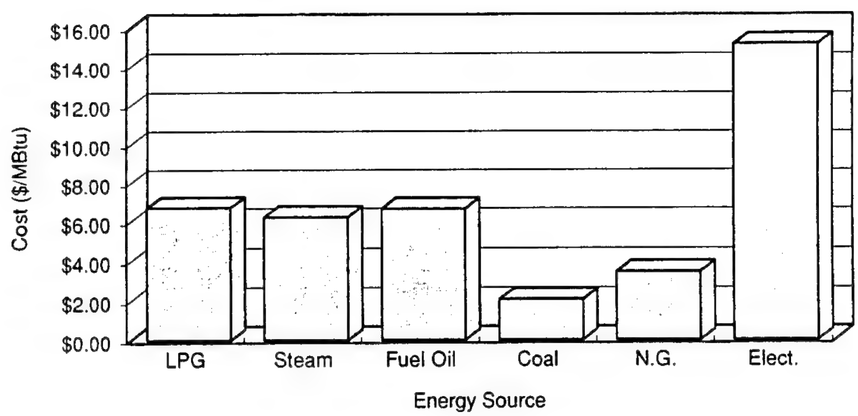

Figure 21. DOD unit energy costs for FY91, CONUS.

Gas Cooling REEP Analysis for the U.S. Army/DOD

Army and DOD-Wide Analysis

To gain a broader perspective of the benefits of gas cooling retrofits, analyses were conducted with the Renewables and Energy Efficiency Planning (REEP) (Nemeth June 1995) software developed at USACERL. The REEP software performs a generalized energy/financial/pollution analysis for energy-saving technologies at up to 250 DOD installations in the continental United States. Facility data, weather data, utility rates, and electrical generation mix are all contained in installation database files. An initial analysis applies algorithms to the various data to produce energy savings estimates. These estimates are then used in an economic analysis that considers regional pricing and life-cycle factors. The economic analysis is based on the DOD's Energy Conservation Investment Program's (USAEHSC March 1993) (ECIP) standards. The economic results are then filtered through user-set minimum requirements. For these analyses, a technology was considered economically viable if it had a simple payback of 10 years or less, and a savings-to-investment ratio of 1.25 or greater. To address the possibility of competing energy technologies, the analyst can then select competition criteria (like simple payback) and run a separate analysis to exclude less attractive competing technologies. Pollution abatement estimates and societal savings

are then calculated based on the energy savings and regional electrical generation mix. Finally, all of the results are totaled across the selected installations. REEP software is explained in detail in Nemeth (June 1995).

REEP analyses were performed for 110 Army and 250 DOD installations for direct-fired gas absorption chillers, gas engine chillers, and high efficiency electric chillers. A full-cost economic analysis was performed within three size ranges: 5 to 50 tons, 50 to 100 tons, and greater than 100 tons. It was assumed that 60 percent of the existing chillers are candidates for replacement (i.e., the chillers are relatively old and a gas supply is available). The benefits of thermal recovery and CFC phaseout were not considered in the economic analysis; however, the additional cost of increased water usage was. Because these three chiller types directly compete for retrofit opportunities, a competition analysis was also conducted. This assured that gas cooling technologies were only considered at sites where they are more cost-effective than high-efficiency electric retrofits. The end results for the Army and the DOD are summarized in Tables 4 to 7. The results are for the gas cooling technologies only.

Of 233 potential applications REEP identified for gas chillers Army-wide and 1640 DOD-wide, simple paybacks are 6.6 and 5.5 years, respectively (Table 4). Roughly $240 million in savings are available DOD-wide (over the lives of the retrofits) for an initial investment of about $100 million.

Table 4. Gas cooling financial results.

Financial Parameters	Army	DOD
No. of candidate chillers	233	1,640
Total investment (million $)	19.1	101.4
Total savings (million $)	36.7	241.4
Annual savings (million $)	2.9	18.4
Simple Payback (years)	6.6	5.5
SIR	1.9	2.4

From the energy perspective, large savings in both electrical demand and purchased electricity can be achieved (Table 5). By contrast, natural gas and water consumption increases (Table 6). Care should be taken in comparing the reduction in electrical energy consumption with the increase in natural gas consumption on a unit-of-electricity to unit-of gas basis. Such a comparison is deceptive because, although there is an apparent net increase in energy consumed, the energy values of the electrical generation fuel mix have not been backed out (i.e., the electrical savings are site, not source values).

Table 5. Gas cooling resource reductions.

Savings		Army	DOD
Site Demand Savings	(kW)	22,281	113,166
Site Electric Savings	(kWh/Yr)	62,235	354,212
	(MBtu/Yr)	201,324	1,208,686

Table 6. Gas cooling resource increases.

Resource	Army	DOD
Gas (MBtu/yr)	497,565	2,988,719
Water (k gallons/yr)	19,969	119,494

Table 7. Net gas cooling pollution abatement.

Pullutants / Savings	Army	DOD
SOx (tons/Yr)	462	1,960
NOx (tons/Yr)	44	-26
Particulates (tons/Yr)	24	101
CO (tons/Yr)	-2	-13
CO_2 (tons/Yr)	23,033	80,279
HC (tons/Yr)	1	5
CFCs(pounds)	110,870	561,690
Societal Savings (Million $/Yr)	2.3	9.2
Note: Negative values indicate an increase of the pollutant.		

Table 7 shows the pollutants abated as a result of this retrofit. These values are for fuel-switching only; they do not reflect any thermal recovery savings. Each source fuel (gas, oil, coal) is assumed to have a particular energy content and to produce a certain amount and mix of pollutants per unit of contained energy. Regional electrical generation mixes and assumed plant and delivery efficiencies are used to back out the source fuel pollution production for each unit of electrical energy. The pollution decrease from the electrical energy savings are then subtracted from the pollution increase from the gas consumption increase. From a net perspective (considering electrical savings *and* gas consumption increases), gas cooling technologies nearly always *decrease* the production of air-borne pollutants. Exceptions are CO and NOx. (Stroot, Nemeth, and Fournier December 1994) contains a detailed explanation of pollution abatement calculations and the assumed pollution production and energy content values. The quantity of CFCs abated assumes that the replaced chillers are older models containing CFC refrigerants and that 2.2 lb of CFCs are recovered per ton of cooling replaced.

Societal costs assigned to these pollutants provide the societal savings seen in the last row (Stroot, Nemeth, and Fournier December 1994) . These savings are not used in the financial analysis that produced the results in Table 4. However, they do provide interesting estimates of environmental savings that may some day be present in energy-conservation evaluations. Yearly societal savings are nearly equal to the annual energy savings for the Army and roughly half the savings for the DOD.

Environmental Implications of Gas Cooling Technologies

Certain environmental issues associated with cooling technologies in general deserve discussion, including not only CFC, HCFC, HFC refrigerant issues, but also environmental issues that result from generating electricity in a power plant and or combusting natural gas in an absorption or engine-driven chiller. The analysis process outlined here has been expanded to include engine- driven chillers, which were not included in the referenced work and are presented as a summary of results from Calm (August 1992) (EPRI Global Warming).

Ozone Depletion

Recently, much concern has arisen over the environmental issues surrounding the use of chlorofluorocarbons (CFCs) in chillers. Many studies have concluded that, at least to some extent, the destruction of the earth's protective ozone layer is linked to the release of CFC refrigerants. The destruction is caused by the reaction of the chlorine and bromine in the CFC molecules with ozone in the stratosphere. This catalytic reaction enables each atom of chlorine or bromine to destroy many—on the order of 100,000 more—ozone molecules.

Chiller manufacturers (both electric and gas engine driven) are no longer shipping chillers that use CFC refrigerants and have therefore reduced the continued growth of the ozone depletion that could have been caused by new chillers currently being sold. Still, this does not eliminate problems associated with existing installed chillers that use CFC refrigerants.

Global Warming

A second environmental concern is global warming. On a daily and seasonal cycle, the earth is heated by solar radiation and the cooled during the night and winter months by radiating this energy back into space. Through many heating and cooling cycles over many years, the temperature of the earth has reached an equilibrium temperature range since, as the earth's temperature increases, so does the back radiation. Equilibrium is reached when the incoming solar radiation equals the cooling back radiation. Many factors determine the equilibrium temperature including solar radiation levels and atmospheric gases and particulates.

While solar radiation does fluctuate as a result of sun spots and other solar activities, the radiation level has remained nearly constant over a very long period. By contrast, the atmospheric conditions have been rapidly changing as the earth's population increases and more recently, as people rely on more combustion processes to meet the

needs of their daily lives. Such processes as driving automobiles and using electric appliances, along with many manufacturing processes, create emissions that continuously change the composition of the atmosphere, reducing it's ability to back radiate the incoming solar radiation. This causes a net increase in thermal energy at the earth's surface and an increase in equilibrium temperature generally referred to as the "Greenhouse Effect."

Alternative Refrigerants

Many refrigerants in common use in vapor compression (VC) chillers today were chosen for their high thermodynamic efficiencies, molecular stability, and low toxicity, flammability, and cost. Until recently, these were considered to be nearly ideal refrigerants since their Ozone Depletion Potential (ODP) and Global Warming Potential (GWP) were not included in the determination of the "ideal" refrigerant. Today this is not the case. ODP and GWP, along with energy efficiency, are primary characteristics to consider when selecting a chiller, which is an investment made typically for 20 to 30 years. In other words, the current definition of the "ideal" refrigerant has changed.

There are other alternative refrigerants for vapor compression chillers, but their selection typically consists of compromises and ultimately, the selection of a less than ideal refrigerant. One alternative is Ammonia, widely used in the food industry, but more toxic than other refrigerants and also corrosive and incompatible with copper, which is a common material used in heat exchangers. Propane or blends of propane and fluorocarbons have been used in the United States and are currently being evaluated for use in Europe. Due to its flammability, it is unlikely that it will be used other than in very special applications.

Another alternative refrigerant receiving more attention in recent years is water. Water, used in conjunction with lithium bromide in absorption chillers, has been used for many years in a wide variety of applications. Water is stable, nontoxic, nonflammable, inexpensive, and has zero ODP and GWP.

Implications of Refrigerant Selection

Each of the discussed refrigerants has advantages and disadvantages. The decision to select one over another is often made on the basis of which chiller manufacturer the owner is familiar with, the lowest initial cost or possibly the lowest life cycle cost, or for any of a number of reasons, usually based on economic figures with little or no concern for the environmental implications of the decision. The following sections

briefly discuss one of the primary environmental issues of today—global warming—and the impact the selection of a specific type of chiller can have on the environment. For comparison, three different chiller types are discussed, electric vapor compression as the base case, natural gas engine-driven vapor compression, and double-effect, direct-fired absorption chillers.

Since this report is focused on new chillers and since the issues associated with ODP have essentially been addressed by banning sales of chillers using CFC refrigerants, issues concerning ODP will not be discussed here; only GWP issues will follow.

Calculation of Global Warming Impact

Global warming as a result of operating a chiller is presented here in two distinct parts: (1) the direct effect, global warming that results from chiller leakage and/or venting of a refrigerant with a nonzero GWP, and (2) the indirect effect, global warming that results from the combustion of fossil fuels to drive the chiller and associated components. Expressing both the direct and indirect effects as equivalent carbon-dioxide emissions allows the calculation of a net effect referred to as Total Equivalent Warming Impact (TEWI).

In the following sections, the direct and indirect effects are calculated, in the form of a TEWI, for each of the three chiller types discussed: electric vapor compression, natural gas engine driven vapor compression, and double-effect direct-fired absorption chillers. The TEWI is the sum of the direct and indirect equivalent warming impact.

Equivalent Warming Impact—Direct Effect

The direct Equivalent Warming Impact (EWI_d) can be calculated by converting the refrigerant releases to equivalent carbon-dioxide emissions as:

$$\begin{aligned} EWI_d &= [(\text{operational losses}) + (\text{disposal losses})] \times (\text{conversion to equivalent } CO_2) \\ &= [(Q \times RC \times LR \times \text{life}) + (Q \times RC \times DV)] \times GWP \end{aligned} \quad \text{[Eq 3]}$$

where:

Q	=	chiller capacity (tons)
RC	=	specific refrigerant charge (lb/ton)
LR	=	average annual loss rate as a fraction of initial charge (lb/lb-yr)
life	=	expected equipment life (years)
DV	=	disposal venting as a fraction of initial charge (lb vented/lb initial charge)

GWP = global warming potential expressed as equivalent CO_2 emissions per unit of refrigerant (lb CO_2/lb).

Combining terms in the above equation to simplify results in the following equation for the calculation of the direct equivalent warming impact:

$$EWI_d = Q \times RC \times (LR \times life + DV) \times GWP \quad \text{[Eq 4]}$$

Table 8 lists the GWP for the refrigerants considered in this study, namely HCFC 123 for the vapor compression chiller (both electric and natural gas) and water for the absorption chiller.

Table 8. GWP relative to CO_2 for 100-yr ITH.

Refrigerant	GWP
HCFC 123	90
water	~ 0

Equivalent Warming Impact—Indirect Effect

The indirect Equivalent Warming Impact (EWI_i) can be calculated as the product of the energy use and the associated CO_2 emission factor:

$$\begin{aligned} EWI_i &= \text{operating time} \times \text{power used} \times CO_2 \text{ production rate} \\ &= (EFLH \times life) \times \sum (Q \times Pj \times CDF_j) \end{aligned} \quad \text{[Eq 5]}$$

where:

EFLH = equivalent full load hours of annual operation (hr/yr)

P = power per ton for compressor or absorption cycle, auxiliaries, and heat rejection (kW/ton or MBtu/t-h)

CDF = carbon dioxide factor: a calculated multiplier, based on fossil fuel usage, to determine the average CO_2 production from generation of electricity (lb CO_2/kWh_e) or combustion of natural gas (lb CO_2/MBtu)

j = subscript to indicate different power inputs.

Total Equivalent Warming Impact—Annualized

Due to variations in equipment life expectancies, it is appropriate to evaluate TEWI on an annual rather than on a total life basis. To calculate the annualized TEWI, the above equations for the direct and indirect components are added together, then divided by their respective equipment lives. This results in an annual Equivalent Warming Impact (EWI_a) described as:

$$EWI_a = Q \times [RC \times (LR + DV/life) \times GWP + EFLH \times \sum(P_j \times CDF_j)] \quad \text{[Eq 6]}$$

Specific Equipment Types

The general calculation developed in the previous section must now be made specific for each of the different chiller types being evaluated in this study. Specifically, because the different chillers can use a different power source for the prime mover and auxiliaries (electricity and/or natural gas), conversions must be made to the previously defined equation. These conversions allow for analysis of specific equipment using typical manufacturers rating nomenclature (kW/ton, COP, IPLV, etc.)

All chillers discussed below are water-cooled water chillers. Since a given chiller capacity is required to meet a specific cooling load, standard design practices are considered here. The chilled water pump would have the same requirements for each chiller technology and therefore will be neglected in this analysis. Pumping requirements for the chilled water side of the system are independent of chiller type and will be ignored in this study. Electric requirements for the condenser side of the system do vary depending on the system type. This is due to the heat generated by the prime mover that must be removed. In an electrically driven chiller with a motor efficiency of greater than 95 percent the additional cooling load is minimal because the heat has already been removed at the power plant. By contrast, engine-driven and absorption chiller heat rejection systems must not only remove the heat from the conditioned space, but also the heat produced during the combustion in the engine cylinders or in the burner section of an absorption chiller. The electricity required for heat rejection is accounted for and varies depending on chiller type in addition to the energy required for operation of the chiller itself. All terms not yet described are defined at the end of this section for electric, engine-driven, and absorption chillers.

Electric, water cooled vapor compression chiller. Water-cooled chillers require additional electrical power in addition to that used by the compressor, for heat rejection. The modified EWI_a is then:

$$\begin{aligned} EWI_a = & \ Q \times [RC \times (LR + DV/life) \times GWP \\ & + EFLH \times \alpha * (1/\epsilon_e + (1 + 1/\epsilon_e)/\epsilon_r) \times CDF_e] \end{aligned} \qquad \text{[Eq 7]}$$

Natural gas engine-driven, water cooled vapor compression chiller. Water-cooled natural gas engine-driven chillers require electric power for the heat rejection equipment along with the natural gas to power the engine. The modified EWI_a is then:

$$\begin{aligned} EWI_a = & \ Q \times [RC \times (LR + DV/life) \times GWP \\ & + EFLH \times \alpha \times 1/\epsilon_g \times CDF_g + [1/\epsilon_p + (1 + HRF/\epsilon_g + 1/\epsilon_p)/\epsilon_r] \times CDF_e] \end{aligned} \qquad \text{[Eq 8]}$$

Direct Fired Double-Effect Absorption Chiller. Water-cooled absorption chillers require additional electric power for heat rejection equipment along with the natural gas to power the absorber. The modified EWIa is then:

$$EWI_a = Q \times [RC \times (LR + DV/life) \times GWP + EFLH \times \alpha \times 1/\epsilon_g \times CDF_g + [1/\epsilon_p + (1 + HRF/\epsilon_g + 1/\epsilon_p)/\epsilon_r] \times CDF_e] \quad \text{[Eq 9]}$$

And since the GWP for both water and LiBr equals zero, the above equation reduces to:

$$EWI_a = Q \times EFLH \times \alpha \times 1/\epsilon_g \times CDF_g + [1/\epsilon_p + (1 + HRF/\epsilon_g + 1/\epsilon_p)/\epsilon_r] \times CDF_e \quad \text{[Eq 10]}$$

where:

- α = factor to convert Q to kW_e (3.5 kW/ton)
- ϵ_e = annual coefficient of performance (dimensionless)
- ϵ_g = annual coefficient of performance (dimensionless)
- ϵ_r = annual coefficient of performance for electricity used for condenser water pumps and for cooling tower fans and pumps (dimensionless)
- ϵ_p = annual coefficient of performance for electricity used for absorption solution pumps, burner fans, engine jacket cooling water pumps, etc., not directly related to heat rejection of the conditioned space (dimensionless)
- CDF_e = carbon dioxide factor for electricity (lb CO_2/kWh_e)
- CDF_g = carbon dioxide factor for natural gas (lb CO_2/MBTU)
- HRF_{eng} = engine heat rejection fraction; the part of primary fuel heat rejected through the condenser or separate water cooling (dimensionless)
- HRF_{abs} = absorption heat rejection fraction; the part of primary fuel heat rejected through the condenser or separate water cooling (dimensionless).

To complete the calculations for the EWI_a using the above equations, several factors still need to be determined, including the numerical values for the CDF for both electricity and natural gas, chiller performance parameters, initial charge, etc. These values will be determined in the following sections.

Carbon Dioxide Factors

The CDF is the quantity of CO_2 that is produced during the process of generating one unit of useful energy. Typically, CDFs are listed in terms of pounds of CO_2 produced

during the generation of 1 kWh of electricity (lb CO_2/kWh$_e$) or in the production, transportation, and combustion of 1 Million Btu's of natural gas (lb CO_2/MBTU). The electrical CDF depends on many factors, particularly the fuel mix used at the power plant where the electricity is generated. Generally a utility has a variety of plants operating at once and the number and type of fuels used can vary seasonally. Hydroelectric power production is the greatest in the spring and summer. The emission factor for hydroelectric power is zero, as it is for nuclear power, while coal, gas, and oil all have associated emission factors that vary regionally depending on the chemical composition of the fossil fuel in question.

The emission factors for each fuel type can then be multiplied by the kWh of electricity produced using that fuel, summed, then divided by the total number of kWh generated in that region to get a weighted CDF. Estimates of the Emission Factor for each fuel type are listed in Table 9.

Table 9. Estimated U.S. carbon dioxide factor by fuel type for 1995.

Fuel Type	Emissions Factor (lb CO_2/kWh)
Coal	2.163
Natural Gas	1.211
Oil	1.751
Nuclear	0.000
Hydro	0.000
Other	0.000
Weighted Ave.	1.486

Chiller Performance Parameters

For this study, two chiller capacities are analyzed for each chiller type, 300 and 1000 tons. Performance parameters were collected from a number of manufacturers and the averages are presented in Table 10 and used in this study. It is also assumed that the equivalent full load hours (EFLH) of operation will be 2200 hr/yr.

Auxiliary equipment required for proper operation of the chillers evaluated here consist of condenser water pumps and cooling tower fans for the electric chiller; condenser water pumps, cooling tower fans, and engine water jacket pump for the natural gas engine-driven chiller; and condenser water pumps, cooling tower fans, solution and refrigerant pumps for the direct-fired, natural gas absorption chiller.

Table 11 outlines the parameters used for each component in this study.

Table 10. Chiller parameters.

Capacity (tons)	Chiller Type*	Fuel	Refrigerant	Charge (lb/ton)	COP	kW/ton
300	VC	electric	CFC-12	1.75	4.4	0.80
	VC	electric	HCFC-123	1.75	5.4	0.65
	VC	natural gas	HCFC-123	1.75	1.7	
	abs	natural gas	water	–	1.05	
1000	VC	electric	CFC-12	2.3	4.7	0.75
	VC	electric	HCFC-123	2.3	6.0	0.59
	VC	natural gas	HCFC-123	2.3	1.85	
	abs	natural gas	water	–	1.1	

*VC = vapor compression chiller; abs = absorption chiller

Global Warming Potential—Comparison of Results

With the above information, one can easily calculate the annualized global warming effect for each of the chiller types discussed in this report. Since only new chillers are considered here and since HCFC-123 chiller/power generation systems are more efficient, and therefore have less environmental impact than either HCFC-22 or HFC-134a, only this data will be presented. Again, since only new chillers are considered, the loss rate is low (0.5 percent/yr) and the resultant direct global warming effects are very small. For comparison, one other case was evaluated. An older chiller with average efficiency (300 ton 0.8 kW/ton - COP = 4.4, 1000 ton 0.75 kW/ton - COP = 4.7) and with CFC -12 (GWP = 7100) as the refrigerant was evaluated. Data for this case is included in Table 11.

Table 11. Heat rejection equipment parameters.

Heat rejection COP	30
Engine driven parasitics COP	100
Absorption parasitics COP	100
Direct-fired absorption HRF	0.85
Engine-driven chiller HRF	0.35
Note: All values are dimensionless.	

As Table 12 and Figure 22 show, significant reductions in GWP are possible by replacing older, inefficient chillers with new chillers, but not in every case. Reductions are on the order of 20 percent total GWP and nearly all of the direct GWP can be eliminated using new electric or engine-driven chillers. New electric- and engine-driven chillers have virtually identical total GWP for both the 300- and 1000-ton chillers. While the total GWPs are nearly equal, where and how the GWP is generated are different. Since both are vapor compression chillers using the same refrigerant, the direct GWPs are equal—as one would expect. Since the electric chiller uses just electricity (generated by a mix of fossil fuels probably including natural gas) to operate both the chiller and all auxiliary equipment (condenser pumps and cooling tower fans), a GWP is only listed in the electricity column. The gas engine-driven chiller uses natural gas to run the engine along with electricity to operate the water jacket, condenser pumps, and cooling tower fans. While both cases reduce total GWP, the engine driven chiller will actually increase "site" GWP since the electricity, and therefore its associated GWP, were produced at a remote location.

Table 12. Annualized global warming potential for electric, engine driven, and absorption chillers.

		GWP (lb/ton-yr)			
			Indirect		
Chiller Type	Capacity (ton)	Direct	Electric	Natural Gas	Total GWP
Electric	300	64.20	2459.1	0.0	2523
CFC-12	1000	84.37	2321.6	0.0	2406
Electric	300	0.81	2060.3	0.0	2061
HCFC-123	1000	1.07	1884.8	0.0	1886
Natural gas	300	0.81	462.9	1534.4	1998
Engine	1000	1.07	457.8	1410.0	1869
Direct-fired	300	0.00	647.3	2484.3	3132
Absorption	1000	0.00	636.0	2371.3	3007

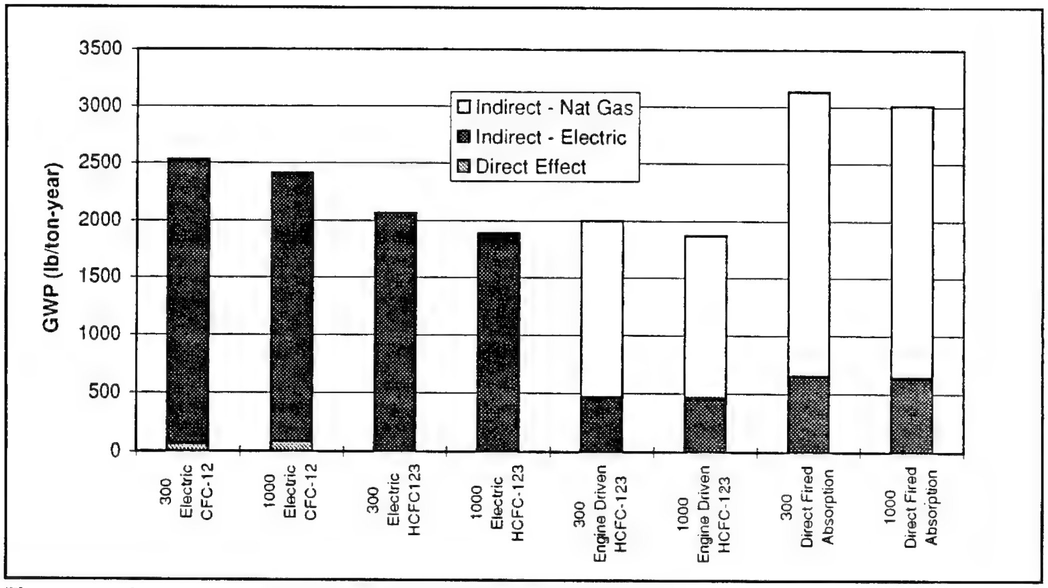

Figure 22. Comparison of direct and indirect effects on GWP.

6 Summary

This study identified absorption and engine driven chiller manufacturers; outlined available chiller capacities; developed guidelines for chiller costs, performance, and parasitic power requirements; and estimated maintenance costs for these cooling technologies. An analysis worksheet was also developed to assist installation personnel evaluate gas cooling technologies and compare owning and operating costs of gas-fueled chillers with those of electric chillers. This worksheet provides a basic analysis tool that ensures a consistent, methodical approach to evaluating these alternative cooling technologies.

It is recommended that, when installation personnel consider chiller replacements, they include off-the-shelf gas cooling technologies in their pool of alternatives. If the worksheet developed in this effort indicates that gas cooling is cost effective, a detailed study should be performed by a qualified engineer to model the specific building(s) and perform a life cycle cost analysis. Barring extenuating circumstances, the lowest life cycle cost option should be selected.

This study concludes that, while gas cooling may not be the best choice for every cooling project, it can be a cost effective option in a wide range of geographic locations, applications, and utility rate structures. Applications are site specific and each project should be carefully evaluated in this light.

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Abbreviations and Acronyms

AGA	American Gas Association
AGCC	American Gas Cooling Center
ARI	Air Conditioning and Refrigeration Institute
Btu	British thermal unit
CFC	Chlorofluorocarbon
CONUS	Continental United States
COP	Coefficient of Performance
dBa	Decibels (on the A scale)
DEIS	Defense Energy Information System
DOD	Department of Defense
DOE	Department of Energy
EDC	engine-driven chiller
EPRI	Electric Power Research Institute
FY	Fiscal Year
gpm	gallons per minute
GRI	Gas Research Institute
HHV	higher heating value
hp	horsepower
hr	hour
IGT	Institute of Gas Technology
IPLV	Integrated Part Load Value
kW	kilowatt, 1,000 Watts
kWh	kilowatt-hour
LHV	lower heating value
LiBr	Lithium Bromide

LPG	liquefied petroleum gas
MBtu	million British thermal units
MBtuh	million British thermal units per hour
MW	megawatt, 1,000,000 Watts
MWh	megawatt-hour
NOx	nitrogen oxides
ppm	parts per million
psi	pounds per square inch
psig	pounds per square inch - gage
rpm	revolutions per minute
scf	standard cubic feet
SOx	sulfur oxides
t-h	ton-hour
USACERL	U.S. Army Construction Engineering Research Laboratories

Appendix A: Absorption and Engine Driven Chiller Evaluation Worksheets

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

1. Facility Name: 2. Date:
3. Prepared by:

COOLING LOAD

4. Peak Load (or installed chiller capacity) tons
5. Hours of Annual Operation (hr/day * days/cooling season) hrs
6. Equivalent Full Load Hour fraction - enter as a fraction [0.00])

7. Monthly Peak Cooling Load (Fraction of Peak Load - [0.00])

A. Jan	B. Feb	C. Mar	D. Apr
E. May	F. Jun	G. Jul	H. Aug
I. Sep	J. Oct	K. Nov	L. Dec

UTILITY RATES

8. Utility Rebates
   A. Electric Utility $ /ton
   B. Gas Utility $ /ton

9. Natural Gas
   Cooling Gas Rate $ /MBtu

Electricity		(A)			(B)		(C)
10. Summer Demand	$		/kW	from		to	
11. Ratchet [0.00]			fraction	from		to	
12. Winter Demand	$		/kW				
13. Energy	$		/kWh				

COOLING EQUIPMENT PERFORMANCE

14. Cooling Equipment Energy requirements (see Figures 7, 8, 9, & 13)

	Chiller Efficiency Peak (1)	IPLV (2)		Auxiliary Electrical Requirements (3)	
A. New Electric			kW/ton		kW/ton
B. Absorption:			COP		kW/ton
C. Engine Driven			COP		kW/ton

15. Heat Recovery (Engine Driven Chiller only)
    A. Usable Thermal Energy Btu/hr
    B. Summer Boiler Efficiency fraction [0.00]

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

16. Equipment and Maintenance Costs (see Figures 4 & 6 and Tables 1 & 2)

	Chiller (1)	Installation (2)	Maintenance (3)	Make-up Water (4)
A. Electric	$ /ton	$ /ton	$ /t-h	$ /t-h
B. Absorption	$ /ton	$ /ton	$ /t-h	$ /t-h
Engine Driven				
C. without HR	$ /ton	$ /ton	$ /t-h	$ /t-h
D. with HR	$ /ton	$ /ton	$ /t-h	$ /t-h

17. Cooling Hours
    A. Annual Equivalent Full Load Hours (5 * 6) EFLH/yr
    B. Annual Cooling Load (17A * 4) t-h/yr

Energy Consumption (Chiller + Parasitics)

18. A. Electric Chiller Energy (17B * 14A2) kWh
    B. Auxiliary Energy (4 * 5 * 14A3) kWh
    C. Total Electricity (18A +18B) kWh

19. A. Absorption Chiller Gas (17B * 0.12 / 14B2) MBtu
    B. Auxiliary Energy (4 * 5 * 14B3) kWh

20. Engine Driven Chiller w/o heat recovery
    A. Engine Chiller Gas (17B * 0.12 / 14C2) MBtu
    B. Auxiliary Energy (4 * 5 * 14C3) kWh

21. Engine Driven Chiller w/ heat recovery
    A. Engine Chiller Gas (20A - 0.00001 * 5 * 15A / 15B) MBtu
    B. Auxiliary Energy (4 * 5 * 14D3) kWh

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

22. Annual Demand Charge - **Electric Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 *22A)	Chiller Demand (kW) (14A1 * 22B)	Auxiliary Demand (kW) 0 or (4 * 14A3)	Actual Demand (22C + 22D)	Ratchet Demand (kW) (max{22E} * 11A)	Billed Demand (kW) (max{22E:22F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (22G * 22H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan									
2	Feb									
3	Mar									
4	Apr									
5	May									
6	Jul									
7	Jul									
8	Aug									
9	Sep									
10	Oct									
11	Nov									
12	Dec									
13	Total Annual Demand Charge (sum{22I1:22I12})									$

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

23. Annual Demand Charge - **Absorption Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 * 23A)	Chiller Demand (kW) (14B1 * 23B)	Auxiliary Demand (kW) 0 or (4 * 14B3)	Actual Demand (23C + 23D)	Ratchet Demand (kW) (max{23E} * 11A)	Billed Demand (kW) (max{23E:23F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (23G * 23H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan									
2	Feb									
3	Mar									
4	Apr									
5	May									
6	Jul									
7	Jul									
8	Aug									
9	Sep									
10	Oct									
11	Nov									
12	Dec									
13	Total Annual Demand Charge (sum{23I1:23I12})									$

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

24. Annual Demand Charge - **Engine Driven Chiller Option**

		Cooling Load Fraction (7)	Cooling Load (tons) (4 * 24A)	Chiller Demand (kW) (14C1 * 24B)	Auxiliary Demand (kW) 0 or (4 * 14C3)	Actual Demand (24C + 24D)	Ratchet Demand (kW) (max{24E} * 11A)	Billed Demand (kW) (max{24E:24F})	Demand Charge ($/kW) (10A or 12)	Monthly Charge ($) (24G * 24H)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Jan									
2	Feb									
3	Mar									
4	Apr									
5	May									
6	Jul									
7	Jul									
8	Aug									
9	Sep									
10	Oct									
11	Nov									
12	Dec									
13	Total Annual Demand Charge (sum{24I1:24I12})									$

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

Owning and Operating Costs - **Electric Chiller Option**

25. Installed System Cost (Electric Chiller)

A. Construction Costs ({16A1 + 16A2} * 4)		$
B. SIOH	(25A * 0.055)	$
C. Design	(25A * 0.060)	$
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$
E. Total Investment (25A + 25B + 25C - 25D)		$

26. Energy Costs (Electric Chiller) - obtain Discount Factor from Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Disounted Cost (5)
A. Electricity	$ /kWh	kWh	$		$
B. Nat Gas	$ /MBtu	MBtu	$		$
C. Demand			$		$
D. Total Operating Cost			$		$

27. Maintenance Costs (Electric Chiller)

A. Annual Maint Cost (17B * 16A3)	$	
B. Discount Factor (Appendix B)		
C. Discounted Maintenance Cost (27A * 27B)		$

28. Make-up Water Cost (Electric Chiller)

A. Annual Water Cost (17B * 16A4)	$	
B. Discount Factor (Appendix B)		
C. Discounted Maintenance Cost (28A * 28B)		$

29. Total Annual Operating Cost (26D3 + 27A + 28A) $

30. Total Discounted Life Cycle Cost (25E + 26D5 + 27C + 28C) $

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

Owning and Operating Costs - **Absorption Chiller Option**

31. Installed System Cost (Absorption Chiller)
    - A. Construction Costs ({16B1 + 16B2} * 4) $
    - B. SIOH (31A * 0.055) $
    - C. Design (31A * 0.060) $
    - D. Utility Rebate, if applicable ({8A + 8B} * 4) $
    - E. Total Investment (31A + 31B + 31C - 31D) $

32. Energy Costs (Absorption Chiller) - obtain Discount Factor from Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Disounted Cost (5)
A. Electricity	$ /kWh	kWh	$		$
B. Nat Gas	$ /MBtu	MBtu	$		$
C. Demand			$		$
D. Total Operating Cost			$		$

33. Maintenance Costs (Absorption Chiller)
    - A. Annual Maint Cost (17B * 16B3) $
    - B. Discount Factor (Appendix B)
    - C. Discounted Maintenance Cost (33A * 33B) $

34. Make-up Water Cost (Absorption Chiller)
    - A. Annual Water Cost (17B * 16B4) $
    - B. Discount Factor (Appendix B)
    - C. Discounted Maintenance Cost (34A * 34B) $

35. Total Annual Operating Cost (32D3 + 33A + 34A) $

36. Total Discounted Life Cycle Cost (31E + 32D5 + 33C + 34C) $

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

Owning and Operating Costs - **Engine Driven Chiller (w/o heat recovery) Option**

37. Installed System Cost (Engine Driven Chiller - w/o heat recovery)
    A. Construction Costs ({16C1 + 16C2} * 4) $
    B. SIOH (37A * 0.055) $
    C. Design (37A * 0.060) $
    D. Utility Rebate, if applicable ({8A + 8B} * 4) $
    E. Total Investment (37A + 37B + 37C - 37D) $

38. Energy Costs (Engine Driven Chiller - w/o heat recovery) - Discount Factor in Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Disounted Cost (5)
A. Electricity	$ /kWh	kWh	$		$
B. Nat Gas	$ /MBtu	MBtu	$		$
C. Demand			$		$
D. Total Operating Cost			$		$

39. Maintenance Costs (Engine Driven Chiller - w/o heat recovery)
    A. Annual Maint Cost (17B * 16C3) $
    B. Discount Factor (Appendix B)
    C. Discounted Maintenance Cost (39A * 39B) $

40. Make-up Water Cost (Engine Driven Chiller - w/o heat recovery)
    A. Annual Water Cost (17B * 16C4) $
    B. Discount Factor (Appendix B)
    C. Discounted Maintenance Cost (40A * 40B) $

41. Total Annual Operating Cost (38D3 + 39A + 40A) $

42. Total Discounted Life Cycle Cost (37E + 38D5 + 39C + 40C) $

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

Owning and Operating Costs - **Engine Driven Chiller (w/ heat recovery) Option**

43. Installed System Cost (Engine Driven Chiller - w/ heat recovery)

A. Construction Costs ({16C1 + 16C2} * 4)		$
B. SIOH	(43A * 0.055)	$
C. Design	(43A * 0.060)	$
D. Utility Rebate, if applicable ({8A + 8B} * 4)		$
E. Total Investment (43A + 43B + 43C - 43D)		$

44. Energy Costs (Engine Driven Chiller - w/ heat recovery) - Discount Factor in Appendix B

	Energy Cost (1)	Annual Consumption (2)	Annual Cost (3)	Discount Factor (4)	Disounted Cost (5)
A. Electricity	$ /kWh	kWh	$		$
B. Nat Gas	$ /MBtu	MBtu	$		$
C. Demand			$		$
D. Total Operating Cost			$		$

45. Maintenance Costs (Engine Driven Chiller - w/ heat recovery)

A. Annual Maint Cost (17B * 16D3)	$	
B. Discount Factor (Appendix B)		
C. Discounted Maintenance Cost (45A * 45B)		$

46. Make-up Water Cost (Engine Driven Chiller - w/ heat recovery)

A. Annual Water Cost (17B * 16D4)	$	
B. Discount Factor (Appendix B)		
C. Discounted Maintenance Cost (46A * 46B)		$

47. Total Annual Operating Cost (44D3 + 45A + 46A) $

48. Total Discounted Life Cycle Cost (43E + 44D5 + 45C + 46C) $

ABSORPTION AND ENGINE DRIVEN CHILLER EVALUATION WORKSHEETS

Incremental Savings-to-Investment Ratio

49 Compare Absorption Chiller to Electric Chiller
(30 - 36) /(31E - 25E)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SIR =

50 Compare Engine Driven Chiller (w/o heat recovery) to Electric Chiller
(30 - 42) / (37E - 25E)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SIR =

51 Compare Engine Driven Chiller (w/ heat recovery) to Electric Chiller
(30 - 48) / (43E - 25E)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SIR =

Incremental Simple Payback Period

52 Compare Absorption Chiller to Electric Chiller
(31E - 25E) / (29 - 35)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SP = yrs

53 Compare Engine Driven Chiller (w/o heat recovery) to Electric Chiller
(37E - 25E) / (29 - 41)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SP = yrs

54 Compare Engine Driven Chiller (w/ heat recovery) to Electric Chiller
(43E - 25E) / (29 - 47)

$$\frac{(\qquad - \qquad)}{(\qquad - \qquad)}$$ SP = yrs

Appendix B: Energy Prices and Discount Factors for Life-Cycle Cost Analysis, FY95

Census Region 1: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania,Rhode Island, Vermont

Census Region 2: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

Census Region 3: Alabama, Arkansas, Deleware, District of Columbia, Flordia, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

Census Region 4: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Table B1. UPV discount factors adjusted for fuel price escalation by fuel type; discount rate = 3.0 % (FEMP).

		Census Region 1		Census Region 2		Census Region 3		Census Region 4	
Year	Non-Fuel	Electric	Nat Gas	Electric	Nat Gas	Electric	Nat Gas	Electric	Nat Gas
1	0.97	0.96	1.00	0.98	1.00	0.98	1.00	0.98	1.00
2	1.91	1.89	1.99	1.93	1.99	1.92	1.99	1.92	1.99
3	2.83	2.79	2.96	2.85	2.97	2.83	2.98	2.83	2.98
4	3.72	3.66	3.93	3.76	3.95	3.71	3.96	3.71	3.96
5	4.58	4.52	4.88	4.65	4.90	4.58	4.92	4.58	4.92
6	5.42	5.35	5.81	5.51	5.84	5.42	5.86	5.42	5.86
7	6.23	6.16	6.75	6.36	6.77	6.25	6.81	6.25	6.81
8	7.02	6.96	7.67	7.19	7.70	7.05	7.75	7.05	7.75
9	7.79	7.72	8.58	8.00	8.61	7.82	8.67	7.82	8.67
10	8.53	8.47	9.49	8.78	9.53	8.58	9.60	8.58	9.60
11	9.25	9.19	10.39	9.55	10.44	9.30	10.52	9.30	10.52
12	9.95	9.90	11.28	10.30	11.34	10.01	11.43	10.01	11.43
13	10.63	10.59	12.18	11.03	12.24	10.69	12.35	10.69	12.35
14	11.30	11.27	13.07	11.75	13.14	11.36	13.27	11.36	13.27
15	11.94	11.93	13.96	12.47	14.02	12.02	14.17	12.02	14.17
16	12.56	12.58	14.84	13.19	14.89	12.66	15.07	12.66	15.07
17	13.17	13.20	15.71	13.89	15.75	13.29	15.96	13.29	15.96
18	13.75	13.82	16.57	14.57	16.61	13.90	16.84	13.90	16.84
19	14.32	14.41	17.42	15.23	17.46	14.50	17.72	14.50	17.72
20	14.88	14.99	18.27	15.88	18.30	15.08	18.58	15.08	18.58
21	15.42	15.56	19.11	16.51	19.13	15.64	19.44	15.64	19.44
22	15.94	16.12	19.93	17.13	19.95	16.20	20.29	16.20	20.29
23	16.44	16.65	20.75	17.73	20.77	16.73	21.13	16.73	21.13
24	16.94	17.18	21.56	18.32	21.58	17.26	21.96	17.26	21.96
25	17.41	17.69	22.35	18.89	22.38	17.77	22.79	17.77	22.79
26	17.88	18.19	23.14	19.44	23.17	18.27	23.61	18.27	23.61
27	18.33	18.68	23.91	19.99	23.96	18.76	24.42	18.76	24.42
28	18.76	19.15	24.68	20.51	24.74	19.23	25.22	19.23	25.22
29	19.19	19.62	25.44	21.03	25.51	19.69	26.02	19.69	26.02
30	19.60	20.07	26.19	21.53	26.28	20.14	26.80	20.14	26.80

Appendix C: Gas Cooling Equipment Manufacturers

This is not intended to comprise a complete listing of gas cooling equipment manufacturers. Only manufacturers with Off-the-Shelf, commercially available HVAC products are listed. Note that the list was compiled in April 1995.

COMPANY	EQUIPMENT	CAPACITY
I. Absorption Chillers		
Carrier (Ebara) Carrier Corporation P.O. Box 4808 Syracuse, NY 13221 Doug Rector 315/432-7152 or Contact Local Office	Direct Fired, Double Effect Chiller-Heater (Ebara) Steam Fired, Double Effect Chiller (Ebara) Steam Fired, Single Effect Chiller	135 - 1000 tons 100 - 1700 tons 100 - 680 tons
McQuay (Sanyo) Snyder General Corp 13600 Industrial Park Blvd. Minneapolis, MN 55441 Dave Olson 612/553-5411	Direct Fired, Double Effect Chiller-Heater (Sanyo) Steam Fired, Double Effect Chiller (Sanyo)	20 - 1500 tons 100 - 1500 tons
Robur (formerly Dometic/Servel) Robur Corporation 2300 Lynch Road P.O. Box 3792 Evansville, IN 47711 Jim Robinson 812/424-1800	Direct Fired, Single Effect Chiller-Heater Direct Fired, Single Effect Chiller	3 - 5 tons 3 - 25 tons
Trane (Kawasaki) Trane Company 3600 Pammel Creek Road La Crosse, WI 54601-7599 Mike Byars 608/787-2885 or Contact Local Office	Direct Fired, Double Effect Chiller-Heater (Kawasaki Thermachill) Steam Fired, Double Effect Chiller (Trane design) Steam Fired, Single Effect Chiller	100 - 1100 tons 385 - 1060 tons 100 - 1660 tons
Yazaki American Yazaki Corp. 13740 Omega Road Farmers Branch, TX 75244 Trevor Judd 214/385-8725	Direct Fired, Double Effect Chiller-Heater Steam/Hot Water Fired, Single Effect Chiller	30 - 100 tons 5 - 10 tons
York (Hitachi) York International P.O. Box 1592 York, PA 17405 Jim Furlong 717/771-6355	Direct Fired, Double Effect Chiller-Heater (Hitachi Paraflow) Steam/Waste Heat Fired, Double Effect Chiller (Hitachi Paraflow) Steam Fired Single Effect Chiller	120 - 1500 tons 250 - 1500 tons 120 - 1377 tons

COMPANY	EQUIPMENT	CAPACITY
II. Engine Driven Systems		
Alturdyne Alturdyne Energy Systems 8050 Armour Street San Diego, CA 92111 Joe Browning 619/565-2131	Reciprocating Chillers Screw Chillers	30 - 200 tons 300 - 1000 tons
Carrier Carrier Corporation P.O. Box 4808 Syracuse, NY 13221 Dan Williams 315/432-3227	Rooftop DX System	25 tons
Econochill Algas-Interex 7907 212th St., S.W. Edmonds, WA 98026-7571 George Lander 206/774-6681	Reciprocating Chillers	40 - 300 tons
EnChill EnChill by MKW Power Systems, Inc. 785 Grand Ave., Suite 206 Carlsbad, CA 92008 Don Anderson 619/720-1500	Reciprocating Chillers Screw Chillers Centrifugal Chillers	50 - 300 tons 250 - 1,000 tons 1,000 - 4,000 tons
H.E.P. H.E.P., Inc. 516 Cameron Placentia, CA 92670 Mike Patten 714/961-0482	Reciprocating Chillers Custom Chillers	45 - 100 tons Up to 1000 tons
Napps Technology Corp. P.O. Box 1509 Longview, TX 75606 Gene Collum 903/984-2112	Standard and Custom Chiller Packages and Compressor Units	20 - 1000 tons
Tecochill Tecogen, Inc. 45 First Avenue Waltham, MA 12254 Rohit Arora 617/622-1400	Screw Chillers (with automotive derivative engines) Screw Chillers (with industrial grade engines)	50 - 300 tons 340, 485, 725 tons
Thermo King Thermo King Corporation 314 West 90th Street Minneapolis, MN 55420 Bob Ellis 612/887-2461	Rooftop DX Air Conditioners and Split Systems (Integral Heating Option Available)	7.5 - 25 tons
York York International P.O. Box 1592 York, PA 17405	Triathlon™ Natural Gas Heating and Cooling System [Contact: Barry Swartz at 717/771-6340] Centrifugal chillers (venture with Caterpillar) [Contact: Ian McGavisk at 717/771-7514]	3 tons 400 - 2000 tons

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